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Anna Garcia
Executive Director

444 N. Capitol St. NW
Suite 638
Washington, DC 20001
(202) 508-3840
FAX (202) 508-3841
e-mail: ozone@otcair.org

October 1, 2010

Lisa P. Jackson, Administrator
U.S. Environmental Protection Agency
Air and Radiation Docket
Mail Code 6102T
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

RE: Proposed Rule – Docket No. EPA-HQ-OAR-2009-0491

Dear Administrator Jackson:

The Ozone Transport Commission (OTC) appreciates the opportunity to comment on the Environmental Protection Agency's (EPA's) proposed rule, "Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone (40 CFR Parts 51, 52, 72, 78 and 97)," also referred to as the "proposed Transport Rule." Transported ozone and particulate matter pollution endanger the health of our citizens, particularly the very young and elderly, and cause lung damage, respiratory illness and premature mortality. Reducing power plant emissions of NOx and SO2 is a crucial part of protecting public health and assisting states in meeting their Clean Air Act obligations.

EPA is to be commended for taking bold steps to resolve the issues that caused the Court to remand the Clean Air Interstate Rule (CAIR) and to develop a new framework for assessing transport that allows for quicker resolution of the serious air quality and health problems to which transport contributes. OTC commends EPA for addressing the Court's and the states' concerns about the relationship between emission reductions and downwind contributions. OTC believes that EPA's proposed methodology for assessing transported air pollution, with the modifications we outline in our comments, can provide a framework for quickly analyzing the impact of transport for future revised national ambient air quality standards (NAAQS). We strongly support EPA's proposal to limit the degree to which power plants can engage in interstate trading of emissions and to not allow the use of the existing NOx and SO2 allowance banks. We also fully support EPA in setting a threshold of 1 percent of the NAAQS for identifying significant contribution and for setting stringent SO2 emissions budgets for 2012 and 2014, both of which will help achieve critical and substantial health-protective emissions reductions and air quality benefits as expeditiously as possible.

Despite past efforts of EPA and the OTC states, our region continues to feel the effects of overwhelming pollution transport. OTC's comments that follow are intended to help EPA improve the current proposed Transport Rule and future Transport Rules with specific suggestions and recommendations that will enable us to achieve our mutual air quality and public health goals.

EPA must fully remedy transport by eliminating all significant contribution and interference with maintenance associated with the 1997 ozone standard, and ensure that the regulatory framework aligns with Clean Air Act deadlines. While we believe that EPA is working toward a sound and strong program to remedy transport with this proposed Transport Rule and a promised next Transport Rule focused on the new ozone standard (referred to herein as Transport 2), we are disappointed that this proposed Transport Rule does not provide a full remedy for the 1997 ozone standard, nor did EPA attempt to address the current ozone standard, set at 75 ppb in 2008, even while reconsidering this standard.

OTC believes that the proposed Transport Rule does a more thorough job of dealing with the transport of SO2 emissions that contribute to PM2.5 pollution than it does for NOx and ozone, which is OTC's primary concern. For example, the proposed rule outlines a program that provides a 16 percent reduction in seasonal NOx emissions and a 36 percent reduction in annual NOx, while SO2 is reduced by 45 percent overall in the region, and some states' SO2 emissions are reduced by as much as 68 percent. The proposed rule does not provide sufficient NOx controls that are feasible to implement by 2014 to eliminate significant contribution and interference with maintenance for the 1997 ozone standard, which will significantly and negatively impact the states of the Ozone Transport Region (OTR).

OTC believes that the regulatory framework proposed by EPA could be substantially improved. First, EPA should align the timetable of the transport remedy with the timing of SIPs per the CAA. For the states to have any chance of developing timely plans to address transport, EPA *must* identify the reductions needed to eliminate significant contribution and interference with maintenance concurrent with the setting of new NAAQS. EPA should quickly apply the new methodology to identify the additional reductions in transport that will be needed for the new ozone standard EPA expects to issue later this year. Second, EPA should provide a FIP-SIP mechanism that allows a state the ability to lower its budget to ensure there will be no backsliding from current control levels. Third, EPA should tie SIP approvals to resolution of any shortfalls in upwind states' planned reductions where elimination of significant contribution and interference with maintenance is not achieved.

These changes to EPA's regulatory framework in the proposed Transport Rule would both provide a better regulatory base for future rule promulgation by EPA, as well as help states in the OTR come into attainment with future NAAQS.

EPA must re-examine the thresholds it uses for identifying potential controls, include a transition to unit-specific performance standards, and revisit its decision to exclude non-EGU sources in the proposed Transport Rule, which we believe are vital to helping states come into attainment with the ozone and PM 2.5 NAAQS. OTC firmly believes that EPA's $500 per ton cost threshold is too low and does not accurately represent what "cost-effective" controls would be under the proposed rule. OTC states have already implemented controls at cost levels far above this threshold that we consider "cost-effective" (we are providing that data to EPA in the attached comments). We believe that cost thresholds should be determined state-by-state, based on the cost of controls necessary to eliminate significant contribution and interference with maintenance, not as a "one size fits all" dollar figure applied across the board.

We also urge EPA to include phased-in unit-specific performance standards (on a 1 to 24-hour time period) in the 2017-2020 timeframe or earlier if reasonable, that are either output-based or will transition to output-based to reward efficiency (as noted in OTC's September 10, 2009 letter to EPA). Further, OTC believes it is critical for EPA to provide incentives to promote the repowering or replacement of existing EGUs, as well as phase out the state caps after unit-specific performance standards are adopted.

Finally, OTC is disappointed that EPA chose to exclude non-EGU sources in the remedy outlined in the proposed rule. OTC provides analyses in the attached comments to support their inclusion in the final Transport Rule, based on work conducted jointly with the Lake Michigan Air Directors Consortium (LADCO) and the OTC states' own experiences in adopting controls from non-EGU sources. It is our expectation that non-EGU sources will be included in Transport 2.

EPA must amend the state emissions budgets and the trading system in the proposed Transport Rule to ensure that no backsliding from current air quality improvements occurs and to assure the remedy will be achieved. OTC believes that the state NOx budgets are not stringent enough due to EPA's use of the $500 per ton cost threshold and use of historical emissions. We are extremely concerned that the methodology EPA has developed unintentionally disadvantages cleaner and more efficient technologies and the sources that are already operating them and "rewards" the dirtiest units with more allowances, and that state budgets in several cases may end up backsliding from their current control levels. We urge EPA to provide states with flexibility in developing their budgets to avoid backsliding.

Further, OTC believes that the variability and assurance provisions could lead to state budget exceedances and that EPA should account for variability within the state budgets and/or on a special case basis via the use of a regional set-aside. We believe this is necessary in order to ensure that the regional and state budgets are not exceeded. OTC also notes that banking in the new trading program needs to include flow control or other mechanisms as assurance that air quality benefits can be achieved. In addition, OTC believes that non-EGU sources should not be allowed to opt-in to any of the trading programs in the proposed rule, especially as an add-on to the state budgets.

Further, despite the substantial technical information and data EPA provided, there was not enough detail for the states to clearly understand how the budgets and other components of the new system were developed and how they are envisioned to work together in the time available. We hope to work with EPA more closely and in advance of future rulemakings to provide assistance with those technical analyses for the next round of transport modeling.

EPA must commit in Transport 2 to develop a full remedy that addresses all appropriate sources in time to allow states to meet their Clean Air Act obligations and deadlines, which will protect public health as expeditiously as possible. OTC has several recommendations in our attached comments for EPA's Transport 2, including using unlimited cost thresholds or state-specific cost thresholds to mitigate transport, applying a diverse, multi-pollutant approach to solve the transport problem, including strong energy efficiency incentives to support clean and efficient energy generation, and implementing OTC's suggested changes to the regulatory framework. We also urge EPA to provide a firm timetable for the issuance of further Transport Rules in order to improve quick implementation of future regulations, and to allow states, industry stakeholders and all affected parties time to develop proper strategies to allow for successful implementation of the rule.

The OTC states have spent years studying air pollution transport and found that it is an important driver of unhealthy air in the Northeast. Published reports have documented that over ninety percent of air pollution can come from out of state during air pollution events. The local measures that OTC states have had to adopt alone have not been sufficient to resolve all air quality problems in the region. This has put OTC states at a disadvantage with other regions of the country that are not required to institute similar strong control measures, even while they continue to contribute significantly to our air pollution problem. Therefore, it is essential to have a strong final Transport Rule that fully achieves its primary mission and sets a sound precedent for future transport rules so that air pollution carried into our region will be controlled and that a reasonable level of local measures can achieve compliance with clean air standards.

We support EPA in its mission to develop a sound and strong program to remedy transport in its two-part solution with this proposed Transport Rule and Transport 2 focused on the new ozone standard. OTC wishes to work closely with EPA as it develops the next rule, and have several recommendations and proposals whose inclusion would help EPA in crafting an effective follow up to the current proposed Transport Rule.

The documents attached to this letter, and its appendices, are intended to provide EPA with details and options for EPA to consider and use in promulgating the final Transport Rule and Transport 2. We welcome further discussion on this issue and offer our assistance to EPA as work proceeds on the development of the final rule. Please contact me at (202) 508-3840 with any questions or concerns.

Sincerely,

Anna Garcia

Anna Garcia
Executive Director

cc: Gina McCarthy, Assistant Administrator, OAR
Janet McCabe, Deputy Administrator, OAR
Joe Goffman, Senior Counsel, OAR
Sam Napolitano, Director, OAR/CAMD

Comments of the Ozone Transport Commission
On
US Environmental Protection Agency Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone
EPA-HQ-OAR-2009-0491

Introduction

Having spent years studying the sources and effects of air pollution transport as an important driver in the development of unhealthy air in the Northeast, the Ozone Transport Commission (OTC) is providing a number of substantial and detailed comments on EPA's proposed ***Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone*** (EPA-HQ-OAR-2009-0491), referred to in our comments as the proposed Transport Rule. Published reports have documented that over ninety percent of air pollution can come from out of state during air pollution events. It is essential that EPA's proposed Transport Rule fully achieves its primary mission and sets a sound precedent for future transport rules. Therefore it is critical to have a strong final Transport Rule, and to continue that foundation in the next transport rule EPA will propose (herein referred to as Transport 2), so that air pollution carried into our region will be controlled and that a reasonable level of local measures can achieve compliance with clean air standards.

Despite past efforts of EPA and the OTC states, our region continues to feel the effects of overwhelming remaining transport. As a result, the states have had no choice but to implement ozone pollution control measures that cost much more than the thresholds EPA includes in the proposed Transport Rule, to reduce NOx emissions from oil-fired boilers serving EGUs, stationary generators and new small gas boilers, and to reduce VOC emissions from consumer products, cleaning solvents, and other, smaller sources . These control options put OTC states at a disadvantage with other regions of the country that are not required to institute similarly strong control measures, even while they continue to contribute significantly to our air pollution problem.

The following comments OTC provides below will help EPA improve the current proposed Transport Rule as well as Transport 2, with specific suggestions and recommendations that will enable us to achieve our mutual air quality and public health goals. OTC also provides a number of detailed studies, evaluations and other data and information as supplements in an Appendix to this document to support our comments and for EPA's use and reference in crafting the final Transport Rule.

I. Current Proposed Transport Rule

OTC's comments on improvements to the proposed Transport Rule focus on several distinct issue areas, including its regulatory framework and the use of Federal Implementation Plans (FIPs) instead of State Implementation Plans (SIPs) and mechanisms to allow for state discretion in allocating allowances. OTC comments on the proposed definitions and methodology used in defining cost-effectiveness and identifying an appropriate cost threshold for controls, as well as for "significant contribution" and "interference with maintenance" by downwind states. In addition, OTC provides comments on the proposed emissions controls requirements from both a control based and trading program perspective. OTC also provides comments on the viability of incorporating end-use energy efficiency standards into the proposed rule. Finally, there is a discussion of several policy concerns held by the OTC and its member states regarding future regulation and expected actions by EPA. OTC's comments on the proposed Transport Rule follow.

1. Regulatory Framework

There are several issues salient to the regulatory framework in EPA's proposed Transport Rule, as well as to any future proposed rule to address transport related to the new ozone NAAQS anticipated later this year. To address these issues, EPA needs to revise aspects of the regulatory framework of the proposed rule to: (1) align the timetable of the transport remedy with the timing of SIPs as required by the Clean Air Act; (2) provide a FIP-SIP mechanism that allows a state discretion in the design of certain aspects of the remedy, e.g., to adjust its budget to avoid backsliding and to allocate the budget to sources in ways that optimize downwind reductions; and (3) mandate resolution of upwind states' emission reductions shortfalls if the federal remedy does not achieve elimination of significant contribution and interference with maintenance within the required Clean Air Act timeframe.

OTC is assuming that EPA views its proposed framework as an approach that can be used in subsequently issued rules to address transport issues associated with future new NAAQS. OTC believes that the framework and process outlined in the current proposed rule should be improved for both this proposed rule and for purposes of addressing transport in a timely manner for future rule issuances.

EPA has taken a step in the right direction by using a Federal Implementation Plan (FIP) in the current proposed framework in order to move pollution controls along the fastest way possible given that this rule is already behind the preceding attempts to control transport.

However, in the future OTC urges EPA to propose a Transport SIP Call and FIP <u>concurrently with any future NAAQS proposals</u>. This would result in the Transport SIP being due 3 years after NAAQS promulgation, or the FIP would become final.

OTC recommends the following changes to EPA's proposed timetable below, with changes and additions in bold/italics:

Year 0:	Finalize NAAQS ***Propose SIP Call*** ***Propose FIP***
Year 1:	Finalize transport SIP call rule and FIP
Year 2:	EPA designations (2 year maximum)
Year 3:	Transport SIP due – controls due 2 – 3 years later ***Final FIP imposed, if no SIP submitted***
Year 5:	Attainment SIP due (3 years after designation)
Year 7+:	Attainment deadlines

OTC believes that these changes will improve the framework of the proposed rule and benefit both the states and EPA in the creation of new transport rules moving forward, as they align with the timetables set in the Clean Air Act as well as achieve notable emissions reductions in a shorter span of time.

OTC also advises EPA to consider following the example set in the Clean Air Interstate Rule (CAIR) that allowed a state to submit an abbreviated SIP, in tandem with a FIP that provided for many of the required elements of the remedy. The idea here is to provide within the Federal framework those elements of the program that are best designed commonly for all states, but allow states to have some flexibility in the allocation of the allowance budgets to ensure that no backsliding from current controls occurs and that reductions targeted at eliminating significant contribution and interference with maintenance are optimized. We elaborate on this issue later in our comments in the section on state budgets and allocations.

Further, OTC also believes that the proposed Transport Rule does not anticipate and address the possibility that, for reasons of timing of controls or other circumstances, the federal remedy may not accomplish the elimination of significant contribution and interference with maintenance by the deadlines stipulated in the Clean Air Act. It is critical that the proposed Tranport Rule include a provision that ties SIP approvals to the resolution of the additional emission reductions in upwind states, as specified by EPA, necessary to achieve compliance with Section 110(a)(2)(D) requirements where the remedy in the federal transport rule proves insufficient to do so. Again, more specific details on this recommendation are outlined in the "remedy options" section of these comments.

2. Cost Thresholds and Cost-Effectiveness

In the proposed rule EPA suggests that a generic $500 per ton level represents the appropriate cost threshold for NOx reductions that can be achieved by 2012. OTC sees at least two major problems with this presumption. First, using this cost threshold for NOx suggests that emission reductions above this level are not "cost effective" for the purposes of the proposed Transport Rule. Second, EPA uses this cost threshold in its rationale for foregoing the option of proposing a second phase of higher cost threshold NOx controls in 2014 in the proposed rule. OTC urges EPA to revise its approach to determining the appropriate NOx controls in the proposed Transport Rule that are feasible to implement by 2014 and that will eliminate significant contribution and interference with maintenance for the 1997 ozone standard.

OTC disagrees with EPA's assignment of a simple $500/ton cost-effectiveness threshold in the proposed Transport Rule, especially when our own states are already enacting NOx control measures at significantly higher costs (see control cost estimates for OTC measures in Appendix 1). Further, EPA states in the proposed Transport Rule that the reductions achieved at this cost threshold will not eliminate significant contribution or interference with maintenance for eleven states linked to ozone air quality problems in New York City. This not only sets a dangerous precedent that the proposed Transport Rule does not have to fully achieve its primary mission, but it also leaves the downwind nonattainment area with the requirement to meet its attainment requirements with controls starting at over ten times the cost per ton used in the proposed Transport Rule. OTC believes that EPA's proposed dollar-per-ton cost thresholds are too low; they do not capture all realizable cost effectiveness, and more importantly, they do not accurately reflect the cost associated with the emissions reductions required for each individual upwind state to eliminate its significant contribution and interference with maintenance.

OTC believes that EPA should determine the amount of emissions each individual upwind state needs to reduce in order to eliminate contribution and prevent the interference with maintenance instead of using a generic “one size fits all” cost threshold figure to determine controls. One alternative, EPA’s remedy option 2 (the intrastate trading only option) provides for higher cost thresholds on a state-by-state basis that would be necessary for some states to meet their responsibility to eliminate significant contribution to and interference with maintenance of another state's ability to meet the NAAQS. The cost effectiveness number will likely be different for each separate state as suggested in EPA's "intrastate only" trading analysis.

Further, where significant contributions are not eliminated by the EPA proposal, OTC believes that it is reasonable to require controls that reflect much higher costs than cited in EPA’s proposed Transport Rule. This is especially true in the case of power plants near the border of another state. Where a significantly contributing plant is the primary cause of a violation of a NAAQS, it must reduce its emissions sufficiently to eliminate that violation. State caps will not ensure reductions at specific EGUs, so it will be necessary to focus on performance standards. OTC believes that the use of a dollar per ton cost threshold to determine emissions controls is inappropriate in this situation. The use of a dollar per ton threshold might be appropriate in order to call for more control than would otherwise be required to meet the receiving states emission limits, especially where a contributing state is not itself requiring available control technologies on its EGU sources.

When EPA addresses the proposed new 2010 ozone NAAQS standard in its next update to the proposed Transport Rule, OTC advocates that EPA first determine the emission reductions necessary to eliminate each state's contribution and interference with maintenance of another states’ ability to meet the new NAAQS standard, and then examine costs. This seems appropriate since, if a state eliminates its contribution or interference with maintenance, any additional reduction does not have as much impact on improving its neighbor’s air quality as compared to local measures.

3. Significant Contribution and Interference with Maintenance

A critical element in the proposed Transport Rule is how significant contribution and interference with maintenance is determined. OTC commends EPA for doing a generally good job assessing significant contribution and interference with maintenance. We offer comments to fine-tune both the determinations themselves and the technical approaches used in EPA’s analyses to develop these definitions.

OTC strongly agrees with EPA’s definition of significant contribution threshold as 1 percent of the NAAQS in the proposed rule. We further support the applicability of this definition for purposes of determining significant contribution in relation to any future NAAQS. However, we urge EPA to make the application of the definition in its proposed Transport Rule consistent with respect to establishing the linkages and then the determination of significant contribution and interference with maintenance as greater than or equal to 1 percent of the NAAQS. As currently written, it is “greater than or equal to” in one place and just “greater than” in another. Specifically , the proposed Transport Rule states that contributions to any downwind sites that are greater than 1 percent of the NAAQS are considered “linked” to those downwind sites for purposes of the second step, in which EPA identifies the portion of each state's "significant contribution" and "interference with maintenance." Our recommendation here proposes that a state whose contribution to any downwind site is "equal to or greater than" 1 percent of the NAAQS be included in those linkages. This recommendation was made by both the OTC and LADCO states previously in their letter dated September 2, 2009 to EPA on the replacement of CAIR (attached as Appendix 2).

OTC appreciates that EPA improved the approach for determining significant contribution from the absolute threshold of 2 ppb that EPA previously used in CAIR, because it sets a relative threshold as a function of the NAAQS for any pollutant. As long as the NAAQS remains unchanged, the threshold will remain constant. However, if the NAAQS are made more stringent, the threshold for the revised NAAQS will also become proportionately more stringent. EPA first uses air quality modeling to quantify individual states' contributions to downwind nonattainment and maintenance sites.

OTC disagrees with EPA's statement on the responsibilities of downwind states under circumstances where all transport is not eliminated. EPA states in the preamble that a downwind state "must adopt controls to demonstrate timely attainment of the NAAQS despite any pollution transport from upwind states that is not eliminated under section 110(a)(2)(D)" (75 FR 45271). Based on recent discussions with EPA, the OTC understands that EPA interprets this statement to mean that section 110(a)(2)(D) has a limited goal of requiring upwind states to eliminate their *significant* contribution to nonattainment in downwind states, not to require upwind states to eliminate all transport. Even after significant contribution from upwind states is eliminated, downwind states might need to address their attainment needs by adopting controls to deal with local contributions to nonattainment or transport that EPA does not consider significant from upwind states. The OTC hopes that EPA will take the opportunity in issuing the final Transport Rule to revise this troubling statement consistent with EPA's intent.

The proposed Transport Rule outlines an entirely new concept of modeling to identify areas projected to be "in nonattainment" or that may be "at risk" in their ability to maintain the standard due to contributions from upwind states. We are concerned that the determinations using this method for purposes of identifying an upwind states' obligation under section 110(a)(2)(D) of the CLEAN AIR ACT may cause confusion with the downwind site's attainment and maintenance determinations for its attainment SIP. Attainment determinations for areas in a state's SIP are calculated using a different methodology and EPA should clarify in the proposed Transport Rule that these are separate determinations with different purposes. We bring this to EPA's attention because OTC is concerned that the ozone and annual $PM_{2.5}$ SIPs already submitted by the states to EPA could be in jeopardy since there are areas (monitors) that were shown to be in "model-based attainment" in those attainment SIPs that could potentially now be considered as areas at risk for interference with "model-based maintenance," per the methodology in the proposed Transport Rule. The implications of this are unknown at this time.

OTC urges that EPA revisit this issue and provide clarification in the proposed Transport Rule or propose guidance that addresses the issue of model-based maintenance as it is applied for section 110(a)(2)(D) purposes to avoid confusion with demonstration of model-based attainment for attainment SIPs.

Alternatively, EPA should strongly consider the September 2, 2009 OTC-LADCO recommendation offers a different method for determining areas of interest, which include areas projected not to meet the standard or struggling to maintain the standard. The OTC-LADCO recommendation proposes the use of both base monitored design values and future modeled design values above the applicable NAAQS as those that should be designated as areas of interest for purposes of addressing significant contribution and interference with maintenance. The monitored design values are based on the maximum design value from the periods 2003 to 2005 through the most recent three-year period. Future modeled values are based on future year modeling which reflects legally enforceable control measures and a conservative model attainment test – i.e., use of maximum design values rather than average design values. The use of maximum design values and a conservative model attainment test are intended to account for historic variability, which is necessary to ensure maintenance. An alternative means of accounting for historic variability is to conduct a statistical analysis of the year-to-year variation in meteorology.

4. State Budgets, Allocations and Variability

OTC also has concerns over EPA's approach to setting state emissions budgets and the allocation of allowances, variability, and the design of the remedy in the proposed Transport Rule. We request that EPA examine other methods for developing and allocating state budgets that address our comments below in this proposed Transport Rule and any future proposed Transport Rule for the upcoming new ozone NAAQS.

Reduce State Budgets and Revise the Allocations

We urge EPA to reduce the state NOx budgets in the proposed Transport Rule for EGU sources in the eastern US to a total of 900,000 tons in 2014, which a recent OTC analysis shows to be technically feasible and cost-effective (see the analysis in Appendix 3) . In addition, EPA should ensure that the 2012 NOx budgets are no higher than those provided under CAIR to avoid backsliding on air quality improvements in downwind areas. OTC finds the state NOx budgets in the proposed Transport Rule to be insufficiently stringent, due to the cost threshold EPA selected in its significant contribution and interference with maintenance analysis that precludes their elimination. We do not understand why some states' NOx budgets set by EPA in the proposed Transport Rule are higher than those under CAIR. For example, in Pennsylvania the annual NOx budget under CAIR is 99,000 tons; under the proposed Transport Rule the annual NOx budget increases to 114,000 tons. According to Pennsylvania's own analysis, this could result in as much as a 20 percent increase in ozone season NOx emissions compared to 2009 levels. While we have read EPA's rationale for not including CAIR in the baseline for its air quality analysis (FR 45233), the OTC states consider budgets in the proposed Transport Rule that are in excess of those that were in CAIR represent significant backsliding In terms of future air quality and public health protections especially considering that current SIPs assumed future transport rules would be at least as stringent as CAIR. Downwind states may not realize as much upwind relief as expected in their current SIPs.

OTC disagrees with EPA's methodology for allocating annual and ozone season NO_x and annual SO_2 allowances. EPA's methodology includes the use of historical emissions rates to determine the number of allowances to allocate to a given EGU. Since emissions rates of units that are uncontrolled for NO_x and SO_2 are greater than those of controlled units, this methodology results in EPA awarding more allowances to dirtier units. Units that acted early to reduce their allowances, such as those controlled under New York's Acid Deposition Reduction Program (ADRP) and Maryland's Healthy Air Act (HAA), are penalized with fewer allowances. This reduces the need for dirtier units to buy allowances from cleaner units, thus also reducing financial incentives for units to install emission controls. It certainly is not good policy to punish those who reduced their emissions earlier than required. OTC urges EPA to redo its allocations based on heat input or output based emissions limits, rewarding the early actors and forcing dirtier units to buy allowances.

OTC is unable to understand how the process described in the preamble for the proposed Transport Rule was used by EPA to develop the ozone season and annual NOx budgets. We have identified several anomalies and request clarification on EPA's methodology. It appears that EPA applies up to three different methodologies in developing the state emission budgets for ozone season NOx. As a result, EPA provides four different values for the ozone season budgets for all 26 states in the proposed Transport Rule. In the Air Quality Modeling Technical Support Document, EPA cites an ozone season NOx budget of 585,584 tons as representing the remedy, but allocates a total budget of 641,614 tons. EPA also cites an ozone season NOx budget of 622,338 tons, after netting out the 3 percent new source set-aside, and we also see a NOx season total budget of 610,454 tons in another of EPA's data tables. EPA explains that they used a combination of historical data and projected data to make adjustments to achieve the final allocated budget (FR 45290 – 45291) but the precise methodology for those adjustments is not well documented in the preamble or supplemental documents, and we are uncertain how these four numbers relate to that process and each other. It is, however, unclear how a remedy that specifies 585,594 tons of NOx emissions supports a trading budget of 641,614 tons.

As further evidence of our confusion with EPA's budget and allocations, in examining the data in the tables in Section IV of the proposed Transport Rule, it is apparent that some states (AL, AR, GA, LA, MI, OK and TX) are allocated near their base case emissions and well over the emissions that would be associated with a $500 per ton cost effectiveness level — while other states (CT, DE, DC, IL, MD, NJ, NY, NC, TN and VA) are allocated budgets that are lower than the emissions associated with a $5,000 per ton cost effectiveness level. The level of NOx emissions at the $5,000 per ton cost effectiveness level for Illinois is higher than those at the $500 per ton level. Anomalies like this raise concerns about the soundness of EPA's allocation methodologies and needs further detailed explanation. EPA states in the proposed Transport Rule that, for states linked to ozone air quality problems in Houston or Baton Rouge, EPA has not yet identified a cost threshold for eliminating significant contribution. EPA does, however, propose to find that those states (AL, AR, FL, GA, IL, KY, LA, MS, TN, and TX) must make at least all of the NOx reductions that can be achieved for $500 per ton in 2012. OTC wonders how the allocation of extra NOx allowances beyond the $500 per ton threshold to states whose significant contributions to nonattainment in those two cities have not been eliminated (in AL, AR, GA, LA and TX) fit with this statement. It is therefore hard to understand why many OTC states are allocated fewer allowances.

Furthermore, unlike the SO_2 budgets, the NOx emission budgets remain frozen at 2012 levels. OTC observes that in setting the SO_2 budgets, EPA provides for two stringency levels that serve to implement the remedy for SO_2 transport. Thus, EPA sets SO_2 budgets in 2012 for Group 1 states that are more stringent than those for the Group 2 states, and Group 1 SO_2 budgets step down further in 2014. We find it unacceptable that NOx budgets are not also reduced in 2014, particularly since additional controls to lower the NOx budgets to a total of 900,000 tons by that timeframe are technically feasible and cost-effective.

OTC also has concerns with using 2009 as a base year for the proposed Transport Rule. Due to economic slowdowns and cooler than normal temperatures across the eastern seaboard, 2009 was a low emission rate year. Lowered electrical demand would result in many units running less or not at all.

OTC compared the emission rate numbers from EPA's modeling (see Table entitled "Allocation vs. IPM vs. Actual" in Appendix 4), to the 2008 emission rates and the 2009 emission rates. EPA is predicting very low emission rates at the $500 per ton level, and OTC believes that these rates are not sustainable in a stronger economy with more typical weather patterns in the Northeast. The values listed may be unattainable if, as EPA's proposed Transport Rule states, no additional NOx controls will be added to the system.

In regard to SO_2 budgets, we also find anomalies. The data presented by EPA suggests that the stringency of controls occurring in the early years is not continuing in later years, at least for some facilities. We find this unacceptable, particularly where later increases in emissions occur at upwind sites. For example, the table in Appendix 5 includes a column labeled "SO_2 Increase" which shows the subtraction of a facility's 2014 allocation from its 2012 allocation. For most facilities, we would expect this would be a positive value, indicating more reductions occurring at a later time. However, the chart shows several facilities to which EPA allocated more SO_2 allowances in 2014 than in 2012. In some instances, this might make sense – if IPM predicts that the facility will be used more. But where those same units have emission rates that are higher in 2012 than in 2014, we fail to understand why extra allowances are allocated to these units for 2014. In such cases, OTC urges EPA to lower the states' SO_2 budget for 2014.

OTC also highlights its concerns that state budget allocations are based on an IPM prediction for which units would likely be dispatched without conducting an uncertainty analysis to determine if these budgets would work if actual unit dispatching turned out to be different. A worst case scenario might have IPM predicting that all dispatched units are on the upwind edge of a state and well away from downwind borders, but the actual dispatching of units might all be located at the downwind edge of the state. This would drastically increase air pollution transport across downwind state lines with the same state emission budget. Therefore, the use of a single IPM predicted dispatching of emissions to develop state budgets does not ensure significant contribution across state lines is fully addressed even if the state budget is met. EPA should conduct sensitivity modeling considering potential variations of unit dispatching the states and then adjust state budgets as needed to improve certainty that significant transport is addressed.

We reiterate our earlier comment recommending that EPA ensure state emission budgets are no less stringent than those allocated under CAIR to ensure there will be no backsliding from current controls and allow states flexibility to optimize reductions targeted at eliminating significant contribution and interference with maintenance. If a State can demonstrate that its allocation methodology is as effective as or more effective in eliminating significant contribution and interference with maintenance than the allocation method in the proposed Transport Rule, the state should be able to use that allocation methodology.

Redefine Variability

With regard to variability, OTC believes that EPA's variability concept in the proposed Transport Rule will not provide the necessary assurances that the current proposed NOx budgets would be met at even a minimum allowable level, especially because the budgets are already lenient. OTC requests that the definition of variability should be revised to only apply to exceptional events, such as natural disasters or the loss of significant non-fossil EGU capacity. OTC further believes that adding variability on top of the emission budgets has the potential to cause an upwind state to exceed the 1 percent significant contribution threshold and that it should instead be factored directly into the emissions budgets. OTC provides a more detailed explanation of these options and the rationale for them below.

In the proposed Transport Rule EPA establishes the concept of variability to address electric reliability, guarding against the possibility that specific budgets assigned to individual states would result in difficulty in maintaining a fluid and adequate supply of electricity among applicable EGUs. EPA cites a number of factors that could contribute to difficulty in maintaining electric reliability such as fluctuations in demand, maintenance, shutdowns, weather, economics and other unpredictable events. EPA asserts that these factors act independently state by state and develops a statistical method of creating a variability allowance of emissions additional to the state budgets established under significant contribution. EPA claims that this does not affect assurance that significant contribution preventing the attainment and maintenance of NAAQS will be eliminated based on two reasons: (1) overall emissions will not increase because additional allowances will not be distributed; and (2) because the baseline emissions are variable, emissions after the elimination of all significant contribution and interference with maintenance are also variable, and thus it is appropriate to take this variability into account. EPA asks for comment on a number of aspects of the variability proposal.

OTC appreciates the need to address variability and agrees with the inclusion of a mechanism to allow for it in the proposed Transport Rule. However, we have significant concerns with the structure EPA has designed to account for variability in the proposed Transport Rule. Many of the factors EPA cites as reasons for establishing variability do not independently affect the impacted states. Instead, groups of neighboring states may be affected simultaneously – a possibility that EPA may not have properly analyzed when designing its variability concept. If a state is an electricity importer, maintenance and shutdowns may affect the surrounding states significantly, which would generate an area of higher emission that could negatively impact downwind states' assurances that significant contribution has been eliminated by their upwind neighbors. Other factors, such as extended episodes of high temperature that often affect large geographic areas exacerbating ozone formation, are a likely scenario that EPA also may not have adequately considered when designing their variability policy for the proposed Transport Rule. While these emission surges may balance out over time, the extra emissions that will result are likely to occur at the worst possible times, like hot, humid days with already poor air quality. EPA claims that these scenarios do not pose a threat because limited allowances will maintain the established emissions levels. However, this interpretation dismisses the fact that sources can have significant carryover allowances from year to year and in a short timeframe can accumulate enough allowances to increase overall emissions in any given year.

Perhaps OTC's greatest concerns with variability is that it is added on to the budget that EPA determined to be the maximum acceptable emissions for addressing significant contribution and interference with maintenance. In addition, EPA has not shown how the use of its variability concept works with a photochemical model.

OTC proposes EPA develop a process for instances of shutdowns and unexpected outages that would utilize allowances from a regional set aside to cover needed interim operations. For other factors, such as extreme weather and increasing demand, potential variability should drive stricter control levels or controls on additional EGU sources and be absorbed under the budget and not included in a revised definition of variability that would only apply to exceptional events, such as natural disasters or the loss of significant non-fossil EGU capacity. EPA's second reason for adopting variability states that just as baseline emissions are variable, emissions after the elimination of all significant contribution and interference are also variable and thus it is appropriate to take this variability into account. EPA has maintained a bright line emission level test as the ultimate standard for approval under their re-designation and maintenance policies. This policy seems fundamentally at odds with EPA's variability concept as enumerated in the proposed Transport Rule, which holds that emissions can fluctuate and at the same time maintain assurance of eliminating significant contribution for downwind states. Consequently, OTC requests that EPA maintain assurance through the individual state budget structure proposed in the proposed Transport Rule and address variability from within that construct; not as an add-on. In addition, OTC would like to see EPA produce a modeling demonstration that verifies variability has been fully examined.

5. Remedy Options

In the proposed Transport Rule EPA outlines three options as the remedy for transport issues concerning the 1997 ozone and 2006 $PM_{2.5}$ NAAQS. All three options focus on achieving reductions in NOx and SO_2 emissions from power plants, and all options are based on a preference stated by EPA to preclude the use or inclusion of existing NOx and SO_2 allowances as part of the remedy. OTC strongly supports EPA's focus on reducing NOx and SO_2 emissions from power plants, but as described later in our comments, we believe EPA should also include reductions from non-EGU sources in the proposed Transport Rule. However, we strongly oppose the inclusion of non-EGU units on an opt-in basis to provide emission reductions in lieu of EGUs covered under the proposed Transport Rule. We also very strongly support EPA's preference to exclude the existing NOx and SO_2 allowance banks in any remedy in the proposed Transport Rule, and below we offer comments on the banking provisions in EPA's remedy options. And while there are aspects of EPA's preferred State Budgets/Limited Trading proposed remedy option that we like and support, we offer improvements to that option drawn from the OTC-LADCO State Collabortive recommendation dated September 2, 2009 and OTC's supplemental recommendation dated September 10, 2009 (attached as Appendix 6). We provide a more detailed discussion of several of these issues below.

Exclude Existing NOx and SO_2 Allowance Banks

The OTC states strongly and unconditionally support the exclusion of the existing NOx and Title IV SO_2 banks from the remedy, as stipulated by EPA in the proposed Transport Rule (FR45338-45339). We agree with EPA and its interpretation of the Court's decision, that any approach to use the Title IV SO_2 allowances "…as not related to, much less necessary for, implementation of the section 110(a)(2)(D)(i)(I) mandate to eliminate significant contribution and interference with maintenance (FR 45338)." We also agree with EPA that, regarding the use of the existing NOx allowances banked either under the NOx SIP call or CAIR programs, these allowances should not be used as part of the proposed Transport Rule remedy. As EPA states, "this approach would avoid the potential legal and practical problems raised by the other approaches, and is the approach proposed by EPA. Similar to the Title IV SO_2 allowances, NOx allowances banked under the NOx SIP Call were designed for a different purpose; i.e., to address transport issues associated with the 1-hour ozone NAAQS. And pre-2012 CAIR allowances are associated with a program that was found inadequate by the Court that is to be replaced by the program in the proposed Transport Rule; when CAIR is replaced any allowances banked under that program should therefore not convey.

Exclude Opt-ins for Non-EGU Sources

OTC also unequivocally opposes EPA's provisions in the proposed Transport Rule to allow the inclusion of non-EGU sources as opt-ins to any of the trading programs. We recall that EPA allowed opt-ins with the NOx SIP call which was not successful. With regard to the proposed Transport Rule, we note two specific aspects of the opt-in provisions we consider completely unworkable. First is EPA's presumption that non-EGUs should be allowed to opt-in to any of the trading programs because non-EGUs may be able to make reductions at a lower cost than other covered (EGU) sources (FR 45308). This is particularly troubling because earlier in the preamble EPA claims that non-EGUs are not included as covered sources because they exceed the $500 per ton cost threshold EPA is holding to and that the Agency has not had sufficient time to develop the technical information necessary to include them in this proposed Transport Rule. Second, EPA proposes that "the allowances created for and allocated to the opt-in unit would be *in addition to* (italics ours) the allowances issued from the state budget and would be usable in compliance by any covered unit (or opt-in unit) just like the allowances allocated from the state budget to covered sources" (FR 45308). The OTC states do not find it acceptable to supplement an already generous emission budget with additional emissions in a system with a 10 percent variability extension on top of the state budgets, despite EPA's assurance provisions and penalties. We see too much opportunity for exceeding the emission budgets and a lessening of potential for location specific (targeted) controls, putting public health at risk.

Strengthen and Combine the Trading and Direct Control Options

Regarding EPA's preferred State Budgets/Limited Trading Option, we recognize the similarity of some elements in that option to the remedy recommended in the September 2, 2009 joint OTC-LADCO State Collaborative letter to EPA. We strongly support the direction EPA is taking to limit interstate trading to mitigate the movement of pollutant emissions across state borders. We urge EPA to strengthen the integrity of the intrastate trading program by including the variability component of the budget within, rather than on top of, the proposed emission budgets. We also strongly recommend that EPA combine the State Budgets/Limited Trading Option with the Direct Control Option by including minimum performance standards in a later timeframe, as OTC recommended in the supplemental letter we submitted to EPA on September 10, 2009 (attached as Appendix 6).

Transition to Performance Standards

In OTC's supplemental letter to EPA the OTC states requested that EPA work with the states to develop and phase in unit-specific performance standards that owners of fossil fuel-fired units should comply with between 2017 and 2025, or earlier if EPA's technical analysis demonstrates that an earlier date is reasonable. We further recommended that the performance standards should be developed on a 1-hour to 24-hour time period in conformance with the appropriate NAAQS, and should either be output-based or transition to output-based standards to reward efficiency. Such performance standards will give greater regulatory certainty to EGU owners and encourage transformational change in the energy market. We also provided the following specifics regarding the development of performance standards for EGUs:

- EPA should consider fuels, types and sizes of EGUs, the timing of other requirements included in this and the September 2, 2009 letter, cost-effectiveness and the pollution control equipment already in place on the existing fleet of EGUs;

- EPA should phase in the performance standards to maximize efficiency and minimize costs to affected sources, for example:
  - The performance standards for coal-fired units greater than 100 MW should be coordinated with the state-by-state caps; and
  - The performance standards for units subject to the upcoming federal MACT requirements should be coordinated with the MACT requirements;
- In later phases (2020 to 2025), the performance standards should be coordinated with greenhouse gas reduction programs and other energy efficiency initiatives and be output-based;
- OTC's analysis (see the Technical Support Document included as part of Appendix 6) shows that performance standards on larger fossil-fuel fired EGUs (based on a 30-day rolling average) are feasible and should be implemented on an aggressive timeframe (as early as 2017);
- EPA should consider including incentives (e.g., alternative compliance schedules not to exceed three years), to promote the repowering or replacement of existing units; and
- After the adoption and implementation of performance standards, EPA should evaluate the feasibility of eliminating the state-by-state caps.

We highly recommend that EPA take the opportunity to include the transition to performance-based standards in the final Transport Rule, and strongly recommend it be included in Transport 2.

<u>Tighten the Banking and Assurance Provisions</u>

OTC has serious concerns with the banking and assurance provisions in all of the remedy options outlined in the proposed Transport Rule. EPA is proposing the state budgets at a level that is supposed to eliminate significant contribution and interference with maintenance. Banked allowances are those saved in one year of a trading program for use in a subsequent year, thus potentially adding to the total amount of NOx or SO_2 emitted into the air in a future year. Without flow control or other mechanisms, the use of banked allowances in any new trading program has the potential to exceed the budget and put the remedy for transport and associated air quality and health benefits at risk. OTC recommends EPA include such mechanisms in any trading program to remedy transport.

In the proposed Transport Rule EPA relies on the assurance provisions to limit emissions that could occur in excess of the state budgets. EPA's approach is to rely on the 1-year and then 3-year variability limits and the requirement that covered sources hold allowances sufficient to cover their emissions as a limit on the incentives to trade, thus ensuring that emissions within states will stay below the budget with the variability limit. OTC finds the design of the assurance provisions at odds with the 3-year timeframe in which states are required to provide clean data in order to demonstrate attainment. With variability limits added on top of the state budgets as well as the opportunity to use unlimited banked allowances created in the new trading program, we are not satisfied that the system will work as EPA foresees to eliminate significant contribution and interference with maintenance over the 3-year period. Surrender of allowances and penalties occur *after* the assurance provisions are triggered over the 3-year timeframe, so there is no opportunity within that time period to correct for the excess emissions. We must therefore strongly recommend that EPA revisit its assurance provisions, in addition to the banking of allowances, incorporating OTC's recommendations to design a program that will guarantee the remedy for transport will be achieved in timeframes that coincide with the CLEAN AIR ACT's attainment requirements.

Finally, earlier in our comments OTC advises EPA to provide that approval decisions on upwind states' SIPs be made contingent upon their resolution of any remaining emission reductions EPA deems necessary to fulfill their obligations under Section 110(a)(2)(D) of the Clean Air Act, in the event the federal remedy does not eliminate significant contribution and interference with maintenance as anticipated.

6. Non-EGU Sources

OTC notes with concern that EPA has excluded non-EGU sources in the remedy outlined in the proposed rule, and urges EPA to consider including them in the final Transport Rule. OTC has long held the position that the inclusion of non-EGU sources is a critical component in any pollution transport regulation promulgated by EPA. OTC views reductions from non-EGU sources as a critical component to allowing OTC's member states the ability to meet the upcoming EPA ozone NAAQS, as well as a forthcoming PM standard. Inclusion of non-EGUs would add flexibility and allow for additional cost effective emission reductions. If non-EGU sources excluded in the final rule, OTC expects that they will be included in Transport 2 for the new ozone NAAQS when it is final, and any future transport rules designed for other future NAAQS.

Based on EPA's projected 2020 emission inventory, the national emission inventory for NOx will no longer be dominated by power plants. Emissions of NOx from EGUs will make up approximately 17 percent of the national emission inventory. On-road mobile emissions will make up about 22 percent of the national NOx emissions, and industrial, commercial and institutional (ICI) boilers and cement kilns will make up a combined 13 percent of the national inventory of NOx emissions. The inclusion of non-EGUs into the proposed Transport Rule will provide a much needed boost in NOx reductions, especially in critical locations. In a joint OTC-LADCO evaluation of emission controls for ICI boilers emissions from these sources are found to be significant. Therefore OTC and LADCO worked together to outline proposed levels of control that can be achieved through existing and reasonable technologies to reduce NOx and SO_2 from this category of non-EGU sources (attached as Appendix 7).

The inclusion of non-EGU sources into a transport rule provides a needed boost in the reduction of air pollution transport into the hard-to-attain portions of the Northeast. In previous work, OTC modeling showed that inclusion of non-EGU source controls produced significantly more benefits and brought more downwind relief, and predicted attainment with air quality standards for many areas.

The University of Maryland College Park (UMD) completed a screening modeling simulation for OTC to illustratively demonstrate the necessary level of emission reductions needed to show compliance with the 8-hour ozone NAAQS in the potential range for the new ozone NAAQS (60 - 70 ppb). This screening modeling simulation covered a time period from May 17 through August 31, 2007, and used a 2007 proxy emissions inventory with the CMAQ model. The emissions reductions for the screening modeling simulation are based on OTC's recommendation for critical national reductions combined with local Ozone Transport Region (OTR) measures (see OTC Resolution dated 6/3/10, Appendix 8). The emissions reductions were applied across the full modeling domain and include emission reductions taken across entire source sectors as specified below:

Domain-Wide

NO_x

Point Sources: -65% (Represents reductions from ICI boilers, cement kilns, and a 900,000 ton regional trading cap on EGUs)
On-road Sources: -75% (Approximates a 2020 national LEV3)
Non-road Sources: -35% (Includes reductions from marine and locomotive engines)

VOCs

All Source Sectors: -30%

OTC States

NO_x

All Sectors: -5% (Additional reductions only in the OTC states)

Results of the UMD screening modeling simulation showed that only one monitor in the OTR had a future year design value over the 2008 8-hour ozone NAAQS of 75 ppb (a summary of the OTC screening modeling analysis is attached as Appendix 9). OTC believes that inclusion of non-EGUs would be more cost effective than other measures that OTC states have already implemented to achieve the 85 ppb ozone NAAQS and current $PM_{2.5}$ standard. OTC recommends that EPA seriously consider including non-EGU sources into the proposed Transport Rule.

7. Modeling and Technical Analysis

The OTC states understand that EPA has been working under direction of the Court to develop its proposed Transport Rule within a short timeframe, which presents challenges in developing supportive modeling and technical analyses. While we appreciate the need for quick analyses to address the Court's deadline, OTC is concerned about the precedent set by EPA as applied to major rules, especially in the future. We understand that in developing the proposed Transport Rule, EPA has a base of existing modeling and technical analysis for CAIR that, while not directly applicable to this effort, does provide some foundation for understanding the issues with and magnitude of the design of a remedy. However, there are existing techniques, which we discuss below, that are available and that EPA should use in completing its analysis for the final Transport Rule, and also for Transport 2.

OTC believes that the Air Quality Assessment Tool (AQAT) makes several over-simplifying assumptions, the first in regards to the direct proportionality between reductions of upwind emissions and downwind ambient concentrations, and the second that emission reductions from all source sectors are equally effective in reducing downwind concentrations. The AQAT may be useful for quickly assessing numerous scenarios in attempting to identify and address significant contribution; however, it should not be seen as a substitute for more detailed air quality modeling to understand the impacts on air quality in greater detail and should be followed up with more accepted modeling techniques for application in the final rule. Air quality modeling systems such as the Comprehensive Air Quality Model with extensions (CAMx) or the Community Multiscale Air Quality model (CMAQ) are publicly reviewed and widely used models, and should be used to develop final budgets and emission reductions needed to address interstate transport, especially in Transport 2. We further request that if EPA is to use new screening tools like AQAT, that they involve the states in development of these analyses so that we can better understand their usefulness and workings prior to employing them. More detailed comments concerning AQAT, CAMx and CMAQ models are provided in Appendix 10.

In developing the mobile source emissions for this platform EPA used the National Mobile Inventory Model (NMIM) with MOBILE6 vehicle emission modeling software, and then applied post-processing to approximate the emissions for this sector that would have been computed with EPA's new mobile source model, the Motor Vehicle Emissions Simulater (MOVES). While OTC supports EPA's choice to use the NMIM and MOBILE6 models to meet the Court's timeframe for developing the proposed Transport Rule, OTC strongly urges that for the final Transport Rule and certainly for Transport 2, EPA undertake modeling with updated mobile emissions based on MOVES. This is particularly important because EPA is requiring the states to use MOVES for their upcoming SIP submissions, and because MOVES outputs both in terms of base emissions and projected reductions from measures are supposed to be much greater than those produced by MOBILE6.

Finally, in the proposed Transport Rule EPA has outlined an entirely new concept of modeling to quantify interference to maintenance for an area by selecting the use of maximum design value based on a five year period and the RRF from model-based estimates of base and future year concentrations. We discuss the policy implications of this new modeling construct earlier in this document.

OTC suggests that the same weighted five-year average for both nonattainment and interference-with-maintenance projections be used. If that approach were used, it would seem reasonable to a) use different future years for the determination of attainment or interference with maintenance (maintenance should come after attainment), and/or b) use a different threshold for the determination of attainment (level of NAAQS) vs. the determination of interference with maintenance (e.g. 95% of level of NAAQS), making sure to reconcile these different thresholds with the "weight of evidence" concept described in the modeling guidance.

II. Transport 2 and Future Transport Rules

As EPA moves forward with developing Transport 2, OTC recommends that: (1) EPA ensure that Clean Air Act Section 110(a)(2)(D) requirements are fully addressed in it and any future transport rules; (2) the regulatory framework be revised as needed to fully address transport in the timeframes required to meet Clean Air Act compliance deadlines as outlined in our comments in Section I; (3) EPA set a higher cost threshold for ozone-season NOx controls as necessary to eliminate significant contribution and interference with maintenance; (4) it also account for the new W-126 secondary ozone standard; and (5) the rule must address transport impacts of SO_2 and NO_2, regard to their specific 1-hour NAAQS.

In order to complete the task under section 110(a)(2)(D) to eliminate all significant contribution and interference with maintenance, EPA needs to include additional reductions in the final Transport Rule that fully address the transport component of nonattainment with the 1997 ozone and 2006 $PM_{2.5}$ NAAQS. EPA acknowledges in the proposed Transport Rule that the Transport FIPs will not completely satisfy the emission reduction requirements of Clean Air Act section 110(a)(2)(D)(i)(I). Two areas—Houston, Texas and Baton Rouge, Louisiana—are expected to still be in violation with the 1997 ozone NAAQS in 2014, while the New York City area is expected to have continued maintenance issues with this standard. In addition, EPA will soon be releasing its reconsidered ozone NAAQS, which will require even greater efforts by upwind states to reduce transport impacts. To solve the additional transport impacts under the soon-to-be revised ozone NAAQS, EPA's next iteration - Transport 2 - will need to be released in a timely manner and contain assurances that upwind impacts will be eliminated within a timeframe that allows downwind states to attain the NAAQS with three years of clean air quality data. It is critical that the precedents set by the currently proposed Transport Rule (with the modifications provided in these comments) are solid and sustainable to application to Transport 2 and to future updates to address transport

As discussed earlier in our comments, EPA's proposed Transport Rule presents a framework that we believe, with some modification, can be adapted for future NAAQS as they are revised. Ideally, reductions from upwind states would come three years prior to the attainment date of a NAAQS; EPA would therefore need to update its next iteration - Transport 2 - for the revised ozone NAAQS in a prompt manner. The OTC recommends that any future proposed revisions to the proposed Transport Rule be released in conjunction with the final revision of a NAAQS. This should prove to be a reasonable timeframe for EPA, and will aid in fulfilling states' obligation to submit a Transport SIP within three years of a new NAAQS being promulgated. We refer you to comments made in Section I of this document on the regulatory framework and ideal timetables for addressing the transport component to meet future NAAQS. Further, OTC believes that there are other issues that need to be resolved in Transport 2 regarding the rule's framework. While we have already focused on portions of the rule framework as they relate to transitioning from the proposed Transport Rule to Transport 2 and future rules, there are additional framework issues and questions that EPA must absolutely address moving forward. For example, will the next rule allow FIPs and SIPs to be simultaneously issued, and if so, what will EPA's strategy with this new policy be to help states achieve measurable emissions reductions? We recommend that prior to proposing Transport 2, EPA convene discussions with OTC and other state groups to get further perspectives on how to strengthen the framework to help states meet their Clean Air Act requirements.

EPA also needs to pursue unlimited or state-specific cost thresholds in Transport 2 and future transport rules to fulfill its statement in the proposed rule that it "intends to proceed with additional rulemaking to address fully the residual significant contribution to nonattainment and interference with maintenance with the ozone standard as quickly as possible," and that it is "expeditiously conducting further analysis of NOx control costs, emissions reductions, air quality impacts, and the nature of the residual air quality issues" (75 FR 45213). The OTC strongly believes that a greater cost threshold must be set for ozone-season NOx controls. While the $500 per ton value in the proposed rule was established only to maintain the operation of already installed SCR units, the large NOx emission reductions which will be required will necessitate the actual installation of new control equipment. And section 110(a)(2)(D) does not confine EPA to regulation of the power sector alone; non-EGU stationary sources are some of the biggest emitters of NOx (and SO_2) in the region. These units would greatly benefit from emissions controls and such reductions would aid in solving the residual effects from upwind states. Compared to the cost of other types of controls implemented by states in the OTR, combustion controls from non-EGUs are cost effective for reducing and/or eliminating transported air pollution (costs of non-EGU controls in the OTR are included in Appendix 1).

We also must point out that Section 110(a)(2)(D)(i)(I) of the Clean Air Act addresses transport "…with respect to any such national primary or <u>secondary</u> ambient air quality standard…" Because the 1997 ozone, 1997 $PM_{2.5}$ and 2006 $PM_{2.5}$ NAAQS all had identical primary and secondary standards, this has not previously been a concern. Transport 2, however, will have to account for the W-126 secondary standard under the ozone reconsideration, assuming it is part of the final NAAQS rule. OTC also notes that a transport analysis of the SO_2 and NO_2 secondary standards, scheduled to be finalized in early 2012, would also be appropriate.

As a final point in this discussion, while EPA has committed to updating its interstate transport determinations for future ozone and $PM_{2.5}$ NAAQS, the OTC feels it important for EPA to also assess transport impacts of SO_2 and NO_2 in regard to their specific 1-hour NAAQS. Section 110(a)(2)(D)(i) calls on states to prohibit the emission of <u>any air pollutant</u> which will contribute significantly to nonattainment or interfere with maintenance of a standard. The proposed Transport Rule notes that "EPA does not expect peak SO_2 levels to be a long-range transport issue" (75 FR 45228) but does not allude to any study that yielded this finding. There is no mention of the recent NO_2 NAAQS. A technical review should be completed to determine if any reduction in the SO_2 or NO_x budget would be required for these recently revised NAAQS. A review of the transport effects of each criteria pollutant upon review of the NAAQS is necessary for the protection of public health in downwind areas.

OTC notes that EPA needs to issue a firm timetable for the issuance of Transport 2 to allow states, industry stakeholders and all affected parties time to develop proper strategies to successfully implement the next rule and have a realistic shot at achieving measurable emissions reductions benchmarks.

<u>Closing</u>

OTC respectfully submits these comments for EPA's consideration in developing a final rule for Federal Implementation Plans to Reduce Interstate Transport of Fine Particulate Matter and Ozone. We welcome further discussion on this issue and offer our assistance to EPA as work proceeds on the development of the final rule.

APPENDICES

1. OTC Stationary and Area Source Committee Updates, OTC Committee Meeting, September 16, 2010, Baltimore, MD
2. OTC-LADCO Joint Letter on Recommendations on CAIR Replacement Rule to EPA, September 2, 2009
3. Evaluation of Alternative NOx Caps for OTC, April 7, 2010
4. OTC Table 1: Allocations vs. IPM vs. Actuals
5. OTC Table 2: 2014 vs. 2012 SO_2 Allocations
6. OTC Supplemental Recommendations Letter and Technical Support Document on CAIR Replacement Rule to EPA, September 10, 2009
7. OTC-LADCO Joint Evaluation for Industrial, Commercial and Institutional (ICI) Boilers Technical Support Document, December 11, 2009
8. OTC Resolution 10-01 Calling on the U.S. Environmental Protection Agency to Adopt and Implement Additional National Rules to Reduce Ozone Transport and Protect Public Health, June 3, 2010
9. Air Quality Screening Modeling: Emissions and Photochemical Modeling, OTC Modeling Committee Meeting, September 16, 2010, Baltimore, MD
10. OTC Detailed Comments on Modeling and Technical Analysis in EPA's Proposed Transport Rule

Ozone Transport Commission Stationary and Area Source Committee Update

OTC Committee Meeting

September 16th, 2010

Linthicum, MD

Stationary and Area Source

NOx Measure	State Rules	Emissions Reduction	Cost
Boilers serving EGUs	DE, NJ,MA, MD	413 TPD OTR	$1,100 - 8,700 per ton
New Small Gas Boilers	CA, TX	53 TPD OTR	$3,300 to $16,000 per ton
Municipal waste incinerators	NJ, MD	14 TPD OTR	$2,140 per ton (SNCR)
HEDD EGUs	NJ	TBD	$45,000 to $300,000 per unit
Stationary Generator Regulation (DG)	DE, MA, MD, NJ	TBD	$39,700 to $79,700 per ton
Minor New Source Review	DE, CT, MD, MA, NJ, RI, PA , VA, VT	TBD	$600 to $18,000 per ton
Energy security / Energy efficiency	TBD	TBD	TBD

Stationary and Area Source

VOC Measure	State Rules	Emissions Reduction	Cost
AIM rule	CA	50 TPD OTR	$2,240 per ton
Auto Refinishing	CA	21 TPD OTR	$2,860 per ton
Consumer Products 2006	CA	19 TPD OTR	$7,700 per ton
Lower VOC Solvent Degreaser	MD, CA	13 TPD OTR	$1,400 per ton
Gas Stations	TBD	TBD	TBD
Large VOC Storage Tanks	MD, NJ	TBD	$2,288 to $29,000 per ton
Minor New Source Review	DE, CT, MD, MA, NJ, RI, PA, VA, VT	TBD	TBD

Updates on Measures

- March 2010, OTC Committee Meeting
  - Presented draft Model Rules for several stationary and area source sectors
  - Sought additional stakeholder comments
- June 2010, OTC Annual Meeting
  - Presented Stakeholder comments
  - Committee made several recommendations to the Commission
- September 2010, OTC Committee Meeting
  - Presenting draft Model Rules on Stationary Generators, HEDD, Low Solvent Degreasers
  - Seeking stakeholder comments

Updates on Other Measures

- Other NOx Measures Under Review
  - Municipal waste incinerators
  - Energy efficiency / renewable energy
- Other VOC Measure Under Review
  - Stage 1 and 2 controls

Stationary Generators

- Consistent definition of "emergency"
  - Draft rules proposes a new consistent definition
- Approach for new engines
  - Harmonizing timelines with effective date
  - Focusing on specific NOx limits and proposes NMHC (hydrocarbons), PM and CO limits

Stationary Generators

- Approach for new engines
  - Sync model rule emissions standards with federal standards for new emergency generators
  - Revise to include most stringent NSPS emissions standards for non-emergency generators
- Defense training exemption
  - Included
- Existing generators
  - No additional emissions standards for emergency generators
  - Approximate 90% reduction in emissions for existing non-emergency generators

High Energy Demand Days

- HEDD

  Model Rule Focuses exclusively on turbines, sets the range at 5 to 15 megawatts, and provides definitions for HEDD conditions.
- Applicable to any natural gas, distillate oil fired turbine that is an HEDD unit capable of generating 5 MW or greater.
- Sets standards for subject HEDD turbines that qualify as "Peaking Units," periodic emission monitoring must be conducted for NOx and CO

Low Solvent Degreasers

Solvent Degreasers

- The 2011 OTC Model Rule for Solvent Degreasing is based on an amalgam of two California air district rules; Rule 1122 of the South Coast Air Quality Management District (SCAQMD)as amended May1, 2009 and Santa Barbara County Air Pollution Control District Rule 321(for Remote Reservoir Cleaner only) as amended September 18, 1997.
- Compliance date for this 2011 OTC Model rule is set for January 1, 2014.
- Does not apply to non-VOC HAP solvents
- Covers all parts of the devices, not just metal
- Exempts medical military equipment, and facilities with capture devices

Municipal Waste Incinerators

- Municipal Waste Incinerators
  - Waiting for EPA MACT
    - Pending federal proposal
  - Facility specific limits
  - Establish 24-hour and annual limits
  - Exceptions for start up, shutdown and malfunction

Energy efficiency / renewable energy

- SIP issue, being discussed with EPA on modeling and inventory information and overlap with GHG plans
- Potential revisions to EPA guidance
- Developing pilot projects

Coal Fired Boilers Serving EGUs

- Evaluating EPA’s transport rule
- On hold until after review

Stage I/II Vapor Recovery

- Awaiting EPA's rule on widespread use
- Examining additional reduction opportunities
- Collecting additional data from states
- Evaluating vendor data

Measure Development Process

- Next Steps
  - Pleases submit written comments by September 30th.
    - Underline / strikeout with supplemental comments preferred. Please focus on the emissions impact.
  - Committee Activities
    - Sector specific calls with stakeholders
    - Develop screening modeling inputs and which measures to include
    - Make recommendation to the Commission

Measure Development Process

- Next Steps
  - Continue work on the remaining control measures from original list
  - Identify new measures

APPENDIX 2

September 2, 2009

The Honorable Lisa P. Jackson, Administrator
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, NW
Mail Code 1101A
Washington, DC 20460

Dear Administrator Jackson:

On behalf of 17 states in the eastern half of the U.S., we wish to provide the following recommendations to the Environmental Protection Agency (EPA) to consider as it develops a replacement rule for the Clean Air Interstate Rule (CAIR), in light of the December 23, 2008, remand by the U.S. Court of Appeals for the D.C. Circuit.

The recommendations follow through on the commitment we made in the March 9, 2009, Framework Document to work together to address the transport requirements of Section 110(a)(2)(D) of the Clean Air Act (CAA), and to attain the ozone and PM2.5 National Ambient Air Quality Standards (NAAQS). Please understand that in preparing these recommendations our fundamental air quality objective is to achieve attainment and ensure maintenance of the NAAQS as expeditiously as practicable.

As the result of our collaboration, we recommend for your consideration a framework, which is based on in-depth technical evaluations and a sincere and concerted effort by all states to reach common ground on an overall approach to addressing transport. This comprehensive framework comprises national rules involving significantly contributing states that combine statewide emissions caps and complementary regional trading programs with a state-led planning process to address transport in a multi-pronged and layered approach. While the undersigned states have reached consensus on this suggested framework, there are some regional differences concerning the timing and stringency of electric generating unit (EGU) reductions, and the criteria for determining which states are included in the state-led planning process. In addition, the states differ in their perspectives on whether performance based standards should be part of the strategy.

The Lake Michigan Air Directors Consortium (LADCO) and the Ozone Transport Commission (OTC) will be submitting separate letters to explain their perspectives on these areas of regional differences on implementation of the framework.

Many areas in the eastern U.S. are designated as nonattainment for the current ozone and PM2.5 standards (1997 version), and it is expected that even more areas will not be in compliance with 2008 ozone and 2006 PM2.5 standards. Numerous data analysis and modeling studies have shown that some (not all) of these nonattainment problems are strongly influenced by inter-state transport.

Additional regional emission reductions will be necessary to help states meet the new air quality standards. A timely and robust federal program that requires substantial regional emission reductions from mobile sources, area sources and large point sources such as

EGUs is an essential component of any strategy to reduce interstate transport of air pollution. These reductions are necessary to attain and maintain compliance with the NAAQS.

The undersigned states recommend a 3-step approach, as further discussed below, to establish a framework from which to address the requirements of CAA section 110(a)(2)(D):

1. Identifying areas of interest (i.e., those not meeting the standards and those struggling to maintain the standards);
2. Identifying, based on specific criteria, upwind states which contribute to nonattainment or interfere with maintenance in these areas of interest; and
3. Implementing a multi-sector remedy to meet CAA requirements.

Step 1 - Identifying Areas of Interest

A. While the requirements of Section 110(a)(2)(D) apply to all areas, most attention should be given to those areas not meeting or struggling to maintain the NAAQS. These "areas of interest" should be identified using monitoring and modeling data.

B. Specifically, areas with both base monitored design values and future modeled design values above the applicable NAAQS should be designated as areas of interest. The monitored design values are based on the maximum design value from the periods 2003-2005 through the most recent three-year period, and the future modeled values are based on future year modeling which reflects legally enforceable control measures and a conservative model attainment test - i.e., use of maximum design values rather than average design values.

    1. The use of maximum design values and a conservative model attainment test are intended to account for historic variability, which is necessary to ensure maintenance. An alternative means of accounting for historic variability is to conduct a statistical analysis of the year-to-year variation in meteorology.

    2. Requiring a more conservative model attainment test will necessitate a change in EPA's modeling guidance. EPA should also establish performance criteria to insure that the modeling is capturing transport appropriately.

    3. EPA's approach in CAIR also reflects a "monitored and modeled" test to identify areas of interest.

Step 2 - Identifying Upwind States that Significantly Contribute to Nonattainment or Interfere with Maintenance

A. An upwind state significantly contributes to nonattainment or interferes with maintenance in a downwind area of interest if its total impact from all source sectors equals or exceeds 1% of the applicable NAAQS.

B. Individual state contributions should be determined through a weight-of-evidence approach, including source apportionment modeling.

C. Use of 1% of the NAAQS as the significance threshold is consistent with EPA's approach in CAIR.

Step 3 - Implementing a Multi-Sector Remedy to Meet Clean Air Act Requirements

A two-part process is recommended consisting of: (A) a national/regional control program adopted by EPA for EGUs and additional federal control measures for other sectors, and (B) state-led efforts to develop, adopt, and implement federally enforceable plans for each area of interest that is not expected to attain the standards even after implementation of the national/regional program.

A. National/Regional Control Program

A significantly contributing state (i.e., a state which contributes at least 1% to a downwind area of interest) must comply with the national/regional control program described below.

1. EGU point source strategy (applicable to units $\geq$ 25 MW)
   In adopting a CAIR replacement rule EPA should:

   (a) make federally enforceable through appropriate mechanisms all nitrogen oxide (NOx) and sulfur dioxide (SO_2) controls to comply with the original CAIR Phase I program;

   (b) make federally enforceable through appropriate mechanisms optimization by no later than early 2014 of existing NOx and SO_2 controls;

   (c) make federally enforceable through appropriate mechanisms application by 2015 of low capital cost NOx controls;

   (d) establish statewide emission caps by no later than 2017 for all fossil fuel-fired units ≥25MW. The caps should reflect an analysis of NOx and SO_2 controls on coal-fired units ≥ 100 MW which, in combination with the three measures above, will achieve rates that are not expected to exceed 0.25 lb/MMBTU for SO_2 (annual average for all units ≥25 MW) and 0.11 lb/MMBTU for NOx (ozone seasonal and annual average for all units ≥25 MW) and which will result in lower rates in some states. Previously banked emissions under the Title IV or CAIR programs shall not be used to comply with the state-wide emission caps; and

   (e) to the fullest extent allowed under the Clean Air Act, EPA should work with the states to establish regional emissions caps with full emissions trading to replace the caps currently applicable under CAIR.

Again, there are regional differences on some elements of the EGU point source strategy, including mechanisms for achieving reductions prior to 2017. Further recommendations will be provided in separate letters by LADCO and OTC.

2. Non-EGU point source strategy

   a. EPA should identify and prioritize other categories of point sources with major emissions of NOx and/or SO_2 (e.g., cement plants) based on a review of available emissions inventories and other information, such as source apportionment studies.

   b. For the non-EGU point sources, EPA should identify and evaluate control options for reducing NOx and/or SO_2 emissions. The evaluation should consider the technological, engineering, and economic feasibility of each control option.

   c. At a minimum, EPA should evaluate the technological, engineering, and implementation feasibility, and cost-effectiveness of controlling SO_2 and NOx emissions from industrial, commercial, and institutional boilers $\geq$ 100 MMBTU/hour.

3. Mobile source strategy, such as new engine standards for on-highway and off-highway vehicles and equipment, and a single consistent environmentally-sensitive formulated fuel.

4. Area source strategy, such as new federal standards for consumer products and architectural, industrial and maintenance coatings as originally promised by EPA in 2007

B. State- Led Attainment Planning

The undersigned states recommend the use of a state-led attainment planning process concurrent with developing the transport SIP to address areas of interest that are not expected to attain after implementation of the national/regional control program. The state-led planning effort should involve a key subset of significantly contributing states to develop, adopt, and implement an appropriate attainment strategy. EPA should work with the states to establish criteria for determining which significantly contributing states should be involved in the state-led planning process. Additionally EPA should work with the states to determine the appropriate criteria for each state to satisfy CAA section 110(a)(2)(D). The advantages of this state-led planning effort include:

- A one-size-fits-all federal solution cannot provide the most appropriate and cost-effective solution for each area;
- Attainment planning is more effective and more likely to succeed if it is done on a non-attainment area basis with a key subset of contributing states;
- Additional controls are identified where they are needed; and
- States maintain their responsibility under the Clean Air Act to establish state implementation plans.

Further recommendations on this issue will be provided in separate letters by LADCO and OTC.

The comprehensive framework outlined above represents the culmination of our collaborative work over the past six months. We look forward to working with you further as EPA develops its CAIR replacement rule.

Sincerely,

Amey Marrella
Connecticut

District of Columbia

Douglas P. Scott
Illinois

Indiana

Maine

Maryland

Massachusetts

Michigan

Thomas S. Burack
New Hampshire

Mark N. Mauriello
New Jersey

New York

Ohio

John Hanger
Pennsylvania

W. Michael Sullivan
Rhode Island

Vermont

Virginia

Wisconsin

DRAFT

Estimation of Feasibility of Achieving NOx Mass Emissions Reductions for Zone 1 of the Clean Air Act Amendments of 2010

EXECUTIVE SUMMARY

The Clean Air Act Amendments of 2010 (S. 2995) take a timely and pioneering approach on a multi-pollutant strategy to reduce nitrogen oxide (NOx), sulfur dioxide (SO_2) and mercury emissions from the electric generating sector. The legislation proposes to establish stringent new SO_2 emission caps and require mercury emission reductions that will significantly protect public health and the environment. However, the proposed NOx reductions from electric generating units (EGUs) in the Zone 1 states[1] fall short of what is technologically feasible, reasonable and necessary for healthy air. Furthermore, the proposed NOx reductions are insufficient to comply with federal ozone standards in the Northeast and Mid-Atlantic states (also known as the Ozone Transport Region, or OTR) and to adequately address the transport of pollutants from upwind sources outside the region.

The Ozone Transport Commission (OTC) has therefore undertaken an evaluation to estimate the feasibility of attaining NOx reductions beyond those addressed for Zone 1 of S. 2995 and the potential timing for those reductions. S. 2995 addresses fossil fuel-fired EGUs with a nameplate rating of greater than 25 MW, and calls for a Zone 1 NOx annual mass emissions cap of 1,390,000 tons/year for 2012 through 2014, 1,300,000 tons/year for 2015 through 2019, and 1,300,000 tons/year for 2020 and beyond unless the EPA Administrator determines that NOx mass emissions should be further reduced.

The OTC estimates that it is technologically feasible and reasonable to attain a NOx mass emission cap for Zone 1 of 1,300,000 tons/year for 2012-2013 and 900,000 tons/year beginning in 2014. This analysis was performed with the existing subject EGU fleet, assumes heat inputs similar to those of 2007. The 2012 and 2104 deadlines depend on the use of banked allowances. Further details of the supporting analysis are described in Appendix A.

A cap of 900,000 tons/year of NOx would assist the OTR states in their efforts to meet the 2008 ozone standard of 75 parts per billion (ppb) and a proposed new ozone standard of 60-70 ppb that is currently under consideration. The proposed NOx caps would not impact the schedule for achieving the S. 2995 SO_2 cap and would not jeopardize the health benefits to be realized from SO_2 reductions. Both NOx and SO_2 caps would require the eventual installation of reasonable and feasible controls and it is likely that some plants will concurrently install controls for both pollutants. Additionally, the large pool of available SO_2 allowances is likely to postpone the installation of SO_2 controls until the SO_2 allowance pool is sufficiently depleted to make post-combustion SO_2 controls cost-effective. This lag time for the installation of SO_2 controls would allow resources to be used for the installation of NOx controls without impacting the timeframe to install SO_2 controls.

[1] S. 2995 identifies the Zone 1 states as the District of Columbia and the states of Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Vermont, Virginia, West Virginia and Wisconsin.

From the evaluation the OTC performed to identify and assess more stringent NOx emission caps in a shorter timeframe than those outlined in the Clean Air Act Amendments of 2010 (S. 2995), it appears that tighter NOx emission caps of 1,300,000 tons/year in 2012 and 900, 000 tons/year in 2014 are reasonable and feasible. Given currently available technology, reasonable assumptions regarding installation and constraints, and the use of banked allowances to provide flexibility in the timing of the installation of controls, a 30 percent greater reduction in NOx emissions can be achieved six years sooner in the Zone 1 states than those provided for in S. 2995. Achieving the additional NOx reductions in this timeframe is essential for the Zone 1 states to be able to comply with the current and new ozone standards, to protect public health and to provide healthful air sooner to the people living in the region.

Estimation of Feasibility of Achieving NOx Mass Emissions Reductions for Zone 1 of the Clean Air Act Amendments of 2010

INTRODUCTION

The Clean Air Act Amendments of 2010 (S.2995) establishes a Zone 1 electric generating unit NOx annual mass emissions caps of 1,390,000 tons for 2012 through 2014, 1,300,000 for 2015 through 2019, and 1,300,000 for 2020 and beyond unless the EPA Administrator determines that NOx mass emissions should be further reduced. EGUs subject to S.2995's annual NOx mass emissions cap are fossil-fuel fired EGUs that on or after January 1, 1985 served a generator with a nameplate capacity of 25 MW or greater and produces electricity for sale. The legislation identifies Zone 1 as the District of Columbia and the states of Alabama, Arkansas, Connecticut, Delaware, Florida, Georgia, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Mississippi, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Vermont, Virginia, West Virginia, and Wisconsin.

First an evaluation was performed to determine if Zone 1 NOx emissions reductions beyond those of S. 2995 were technologically reasonable and feasible from the existing fleet of EGUs. The evaluation was to further estimate the potential NOx emissions cap for that fleet of units. The methodology and assumptions used in that evaluation are briefly described in Appendix A. The results of that evaluation indicated that, for the assumptions utilized in the evaluation, it was technologically feasible to attain an annual Zone 1 NOx emissions cap of 900,000 tons (see Table 1 of Appendix A – column "Projected State Total NOx Mass" – fleet total at bottom of column).

Subsequent to determining the technologically reasonable and feasible NOx emission cap for Zone 1, we performed an evaluation to determine a potential timeline for achieving the 900,000 ton/year Zone 1 NOx emissions cap along with potential interim Zone 1 NOx emissions caps.

A summary of the evaluation of technologically reasonable and feasible caps (with greater detail in Appendix A) and evaluation of two timeline scenarios is described in the following sections.

TECHNOLOGICALLY FEASIBLE ZONE 1 EGU NOx EMISSION CAP

Based on an analysis conducted on the individual EGUs in the Zone 1 states according to a set of reasonable assumptions for the application of NOx emission control technology, we conclude that an annual Zone 1 NOx emission cap of 900,000 tons is both reasonable and feasible. The analysis uses EPA CAMD data for Acid Rain EGUs located in the Zone 1. CAMD data was utilized including calendar years 2007, 2008, and 2009. Units included in the analysis were those Zone 1 Acid Rain EGUs that operated in 2009. This population of Acid Rain EGUs included 844 coal-fired boilers, 281oil and gas fired boilers, and 1356 combustion turbine and combined cycle units.

As 2007 is recognized as the last calendar year prior to the current economic turndown, actual individual unit 2007 annual heat inputs were used for estimating an achievable Zone 1 NOx mass cap. For units that came on line subsequent to 2007, the heat inputs used for those units were the actual 2009 annual heat input. For those units that ceased operation subsequent to 2007, those units and their heat inputs were omitted from the mass cap calculations. Wood fired units were not included in the evaluation.

The determination of individual unit NOx emission rates was somewhat more complex, and was performed using the methodology and assumptions outlined in Appendix A. The assumptions used for determining the individual unit NOx emission rates were developed for three different categories of EGUs: (1) coal-fired units, (2) oil and gas-fired boiler units, and (3) combustion turbine and combined cycle units. The results of this analysis providing a determination of NOx emission rates for individual units are summarized by state in Table 1 of Appendix A.

Using the methodology described in Appendix A, it was estimated that it is technologically reasonable and feasible to attain an annual NOx mass emission cap of 900,000 tons/year with the existing subject EGU fleet and assuming heat inputs similar to those of 2007. (Note: For units that started subsequent to 2007, actual 2009 heat input values were utilized.) Estimated potentially achievable Zone 1 NOx mass caps are identified in column 2 of the following table:

Year	Estimated NOx cap (without use of banked NOx allowances)	Estimated Annual NOx Mass Emissions (with SO_2 as priority & use of banked NOx allowances)	Estimated Annual NOx Mass Emissions (with NOx as priority & SO_2 allowances)
2011	1,573,621	1,574,000	1,574,000
2012	1,377,711	1,443,649	1,300,000 (cap)
2013	1,206,500	1,353,293	1,018,000
2014	1,035,844	1,234,212	900,000 (cap)
2015	936,775	1,132,546	
2016	882,578	1,010,220	
2017	872,401	916,303	
2018		900,000	

It is important to note that a cap of nearly 900,000 tons is achievable in 2015 if no banked NOx allowances are used for compliance purposes, and if the timing and constraints for SO2 controls installations are not considered. Columns 3 and 4 of the table provide the results of a bounding analysis for the timing of installations considering a number of constraints and assuming the use of either NOx or SO2 banked allowances. The bounding analysis that is described below shows how the decision to prioritize either the installation of NOx or SO2 controls in an absolute sense affects the timing of achieving the 2012 and 2014 NOx emission caps. In reality, investment decisions on installation of controls lies somewhere in the middle of these bounds. Therefore, the application of controls and the bounding analysis demonstrate the feasibility and reasonableness of the alternative NOx emission caps and timeframes proposed by the OTC.

TIMELINE AND CONTRAINTS FOR POTENTIAL INSTALLATION OF CONTROLS

The EPA has previously performed extensive analysis in the identification of potential constraints for emission control installations related to its evaluation of the Clear Skies Act of 2002 and the Clean Air Interstate Rule (CAIR). Several of EPA's CAIR and Clear Skies Act of 2002 technical support documents were referenced to help identify emission control installation constraints applicable to this evaluation.

Applying these constraints and assuming a priority for NOx controls and the use of banked SO2 allowances as necessary to meet the SO2 annual caps specified in S. 2995, it appears feasible and reasonable to meet a 2012 NOx emission cap of 1,300,000 tons/year followed by a 2014 NOx emissions cap of 900,000 tons/year. A discussion of the potential constraints and an evaluation of potential timelines are provided below.

Time Needed for Installation of Controls

One of EPA's documents (Engineering and Economic Factors Affecting the Installation of Control Technologies for Multipollutant Strategies, dated October 2002) indicated that SCR installation projects could be performed in somewhat less than 24-months. For the purposes of this evaluation, a period of 24-months was assumed to be the average time required for the installation of SCR controls on coal-fired boilers and oil/gas-fired boilers. In addition, a period of 27 months was the assumed average time required for the installation of FGD controls on coal-fired and oil/gas-fired boilers.

Boilermaker Availability

During its CAIR development process, the EPA evaluated boilermaker availability as a constraint on the ability to install EGU emission controls. As part of this evaluation, the EPA estimated the amount of boilermaker hours available to perform emission control retrofits and estimated the number of boilermaker hours to perform such installations. The results of this EPA evaluation, as documented in EPA's document "Boilermaker Labor Analysis and Installation Timing", dated March 2005, included the following data points: there are 28,000 boilermakers; 35% of the boilermakers are available for emission control retrofits; annual hours worked per boilermaker is 2000; 0.152 boilermaker-years are required per MW of FGD retrofit; 0.175 boilermaker-years are required per MW of SCR retrofit; and, 0.01 boiler-maker-years are required for SNCR retrofit. This EPA data was used in the conduct of this evaluation as constraints on the installation rate of emission control retrofits for Zone 1 EGUs.

Timelines and Priority of Achieving NOx Caps vs. SO2 Caps

Another potential and possibly significant constraint on the ability to install NOx controls on Zone 1 EGUs, for the purposes of this evaluation, is that S. 2995 also established annual, USA-wide SO2 mass emissions caps that will require the retrofit of emission controls for compliance. The demand for installation of these controls on a national basis will impact the ability to install Zone 1 NOx controls and will need to be considered in a timeline for their installation.

The first timeline analysis takes consideration of the installation of SO2 controls to meet the annual caps outlined in S. 2995 by 2018 and in the interim years as the priority. For purposes of this evaluation, it was assumed that the installation of SO2 controls would be timed to meet the legislation's 2018 SO2 mass emission national cap without accounting for SO2 allowances in the bank to mitigate the requirements. The simplified assumptions used for the installation of SO2 controls on individual units are identified in Appendix B. To determine the impact on Zone 1 NOx emission control installation capability, it was necessary for this evaluation to include an estimation of the impact of the national demand for SO2 control installation on boilermaker availability. The demand for boilermaker hours required for SO2 control installation was then subtracted from the total number of available boilermaker hours to determine the hours available for installation of NOx controls. This evaluation then focuses on installation of controls to meet a 900,000 ton/year NOx emission cap in 2014 with an interim 1,000,000 ton/year NOx emission cap in 2012, assuming the use of NOx allowances in the bank to mitigate the requirements.

The second timeline analysis takes consideration of the installation of NOx controls to meet the annual caps of 1,000,000 tons in 2012 and 900,000 tons in 2014 as the priority. For purposes of this evaluation, it was assumed that the NOx controls would be timed to meet those national caps without accounting for NOx allowances in the bank to mitigate the requirements. The assumptions used for the installation of NOx controls on individual units are the same as those outlined in Appendix A. This evaluation includes an estimation of the impact of the national demand for NOx control installation on boilermaker availability. The demand for boilermaker hours required for NOx control installation was then subtracted from the total number of available boilermaker hours to determine the number of hours available for installation of SO2 controls. This evaluation then focuses on the installation of controls to meet S. 2995's 2018 SO2 mass emission annual national cap, including accounting for the use of SO2 allowances in the bank to mitigate the requirements.

Timeline 1 illustrates the installation of NOx controls based on the assumption of attaining the 2015 SO2 mass emissions cap of 2,000,000 tons/year in S. 2995 prior to attaining the OTC proposed 2012 NOx mass emission cap of 1,300,000 tons/year and then the 2014 NOx mass emissions cap of 900,000 tons/year. Once the appropriate level of boilermaker years has been utilized for the SO2 installations, any remaining boilermaker years in each year is applied to the installation of NOx controls.

TIMELINE 1: ESTIMATION OF NOx CONTROL INSTALLATION WITH SO2 PRIORITY

Year	Estimated Potentially Feasible Annual Zone 1 NOx Mass Emissions (Cap)	Estimated Boilermaker-yrs Required to Attain (NOx Mass Cap)	Estimated Boilermaker-yrs Available for NOx retrofits (with SO2 as priority)	Estimated Annual Zone 1 NOx Mass Emissions (with SO2 as Priority)	Estimated NOx Allowances Required for Compliance with 1.3-2012/0.9-2014 NOx Caps	Cumulative Estimated NOx Allowances Required for Compliance with 1.3-2012/0.9-2014 NOx Caps
2011	1,574,000	9,013	3,500	1,574,000	N/A	N/A
2012	1,300,000 (cap)	7,844	3,500	1,443,649	143,649	143,649
2013	1,018,000	7,844	3,500	1,353,293	53,293	196,942
2014	900,000 (cap)		3,500	1,234,212	334,212	531,154
2015			4,100	1,132,546	232,546	763,700
2016			4,100	1,010,220	110,220	873,920
2017			4,100	916,303	16,303	890,223
2018				900,000 (cap)		

The assumptions used for this evaluation are as follows:

- Total Available Boilermaker Population – 28,000
- Percentage of Boilermakers Available for Retrofit – 35% (28,000 x 0.35 = 9,800 BM/yr)
- Boilermaker Requirement for 2011-2014 FGD priority retrofits = 6,300 BM/yr
- Boilermaker Availability for 2011-2014 NOx SCR/SNCR retrofits = 3,500 BM/yr
- Boilermaker Requirement for 2015-2017 FGD priority retrofits – 5,700 BM/yr
- Boilermaker Availability for 2015-2017 NOx SCR/SNCR retrofits – 4,100 BM/yr
- Boilermaker Duty Rate for FGD – 0.152 boilermaker-yr/MW
- Boilermaker Duty Rate for SCR – 0.175 boilermaker-yr/MW
- Boilermaker Duty Rate for SNCR – 0.01 boilermaker-yr/MW
- FGD installations occur first on units with highest 2009 total SO2 mass emissions
- SCR/SNCR installations occur first on units with highest 2009 total NOx mass emissions
- Individual unit heat inputs equal to 2007 heat inputs were assumed, except for units that did not operate in 2007 and then the individual unit's 2009 heat input were assumed for those units.

If SO2 installations are considered the priority, the evaluation above shows that the use of banked NOx allowances will be necessary to comply with both the 2012 NOx emissions cap of 1,200,000 tons/year and the 2014 NOx cap of 900,000 tons/year. The total number of banked NOx allowances needed to meet both the 2012 and 2014 NOx emission caps over a six-year period is nearly 900,000 tons. With approximately 300,000 tons of banked NOx allowances available at present, it is unlikely that the NOx allowance bank will grow to this level. However, if there a sufficient bank of NOx allowances was available, greater NOx reductions and associated health benefits would be achieved earlier than those provide by the NOx emission cap levels outlined in S. 2995.A more likely scenario for achieving the OTC proposed NOx emission caps is to prioritize the installation of NOx controls or to allow for a combination of NOx and SO2 control installations to occur.

Timeline 2 illustrates the installation of NOx controls as the priority, using the assumption of attaining the 2012 NOx mass emission cap of 1,300,000 tons/year followed by attaining the 2014 NOx emission cap of 900,000 tons/year. This analysis therefore assumes attaining both NOx mass emissions caps prior to attaining the 2015 and 2018 SO2 mass emission caps in S. 2995. Once the appropriate level of boilermaker years has been utilized for the NOx installations, any remaining boilermaker years in each year is applied to the installation of SO2 controls.

TIMELINE 2: ESTIMATION OF NOx CONTROL INSTALLATION WITH NOx PRIORITY

Year	**Total Available (BM-yr)**	**NOx (SCR) retrofits Required (BM-yr)**	**Difference**	**SO_2 (FGD) Retrofits Required (BM-yr)**	**SO_2 (FGD) Retrofits Available (BM-yr)**	**SO_2 (FGD) Retrofits Shortfall (BM-yr)**	**SO_2 Allowances Needed to Make up the Shortfall**
2011	9,800	9,013	787	6,300	787	5,513	1,102,600
2012	9,800	7,844	1,956	6,300	1,956	4,344	868,800
2013	9,800	7,844	1,956	6,300	1,956	4,344	868,800
2014	9,800	0	9,800	6,300	9,800	N/A	-
2015	9,800	0	9,800	9,800	9,800	N/A	-
2016	9,800	0	9,800	9,800	9,800	N/A	-
2017	9,800	0	9,800	8,200	9,800	N/A	-
2018	9,800	0	9,800	0	9,800	N/A	-

The assumptions used for this evaluation are as follows:

- Total Available Boilermaker Population – 28,000
- Percentage of Boilermakers Available for Retrofit – 35% (28,000 x 0.35 = 9,800 BM/yr)
- Boilermaker Requirement for 2011 SCR/SNCR priority retrofits = 9,013 BM/yr
- Boilermaker Availability for 2011 FGD retrofits = 787 BM/yr
- Boilermaker Requirement for 2012-2013 SCR/SNCR priority retrofits = 7,844 BM/yr
- Boilermaker Availability for 2012-2013 FGD retrofits – 1,956 BM/yr
- Boilermaker Requirement for 2014 & after SCR/SNCR retrofits = 0
- Boilermaker Availability for 2014 & after FGD retrofits == 9,800 BM/yr
- Boilermaker Duty Rate for FGD – 0.152 boilermaker-yr/MW
- Boilermaker Duty Rate for SCR – 0.175 boilermaker-yr/MW
- Boilermaker Duty Rate for SNCR – 0.01 boilermaker-yr/MW
- FGD installations occur first on units with highest 2009 total SO2 mass emissions
- SCR/SNCR installations occur first on units with highest 2009 total NOx mass emissions
- Individual unit heat inputs equal to 2007 heat inputs were assumed, except for units that did not operate in 2007 and then the individual unit's 2009 heat input were assumed for those units.

When installation of NOx controls is considered the priority, the evaluation above shows that the use of banked SO2 allowances will be necessary to comply with the 2015 SO2 emissions cap of 1,200,000 tons/year. The total number of banked SO2 allowances needed to meet the 2015 SO2 emission cap over a three-year period is approximately 2,850,000 tons. With approximately 8,000,000 tons of banked SO2 allowances available at present, there is already a more than sufficient bank of SO2 allowances available, and in this scenario even greater NOx reductions and associated health benefits would be achieved earlier than those provide by the NOx emission cap levels outlined in S. 2995. The full contingent of NOx controls is installed by 2014, allowing for the maximum potential NOx reductions to be achieved in 2014, 2015 and 2016 towards attainment of the new ozone standard, which is anticipated to be set within a range (60-70 ppb) that will be nearly 20 percent more stringent than the 1997 ozone standard (84 ppb).

Furthermore, this scenario shows that the use of banked SO_2 allowances after 2015 will not be necessary to achieve the 2018 SO_2 emissions cap of 500,000 tons/year.

CONCLUSION

From the evaluation the OTC performed to identify and assess more stringent NO_x emission caps in a shorter timeframe than those outlined in the Clean Air Act Amendments of 2010 (S. 2995), it appears that tighter NO_x emission caps of 1,300,000 tons/year in 2012 and 900, 000 tons/year in 2014 are reasonable and feasible. Given currently available technology, reasonable assumptions regarding installation and constraints, and the use of banked allowances to provide flexibility in the timing of the installation of controls, a 30 percent greater reduction in NO_x emissions can be achieved six years sooner in the Zone 1 states than those provided for in S. 2995. Achieving the additional NO_x reductions in this timeframe is essential for the Zone 1 states to be able to comply with the new ozone standards and to protect public health and provide healthful air sooner to the people living in the region.

APPENDIX A
Methodology & Assumptions Used for Installation of NOx Controls in the Analysis

The purpose of this analysis was to determine the technological feasibility of achieving NOx mass emissions reductions beyond the Zone 1 annual NOx mass caps identified in the proposed Clean Air Planning Act. The analysis was performed using EPA CAMD data for Acid Rain EGUs located in the Zone 1. CAMD data was utilized including calendar years 2007, 2008, and 2009.

Units included in the analysis were those Zone 1 Acid Rain EGUs that operated in 2009. This population of Acid Rain EGUs included 844 coal-fired boilers, 281oil and gas fired boilers, and 1356 combustion turbine and combined cycle units.

As 2007 is recognized as the last calendar year prior to the current economic turndown, actual individual unit 2007 annual heat inputs were used for estimating an achievable Zone 1 NOx mass cap. For units that came on line subsequent to 2007, the heat inputs used for those units were the actual 2009 annual heat input. For those units that ceased operation subsequent to 2007, those units and their heat inputs were omitted from the mass cap calculations. Wood fired units were not included in the evaluation.

Determination of individual unit NOx emission rates was somewhat more complex. For coal-fired units, determination of individual unit NOx emission rates was based upon the following criteria:

- For coal-fired units that were identified in CAMD (2009 data) as incorporating SCR or SNCR, the individual unit selected NOx emission rate was the lower of the actual 2008 ozone season NOx emission rate or the actual 2009 annual NOx emission rate.
- For coal-fired units with a heat input rating less than 1000 MMBTU/hr that were identified in CAMD as not incorporating SCR or SNCR, application of SNCR was assumed. The estimated resulting NOx emission rate was calculated as 60% of the lower of the actual 2008 ozone season NOx emission rate or the actual 2009 annual NOx emission rate. A 0.06 lb/MMBTU NOx emission rate floor was also utilized where appropriate.
- For coal-fired units with a heat input rating of 2000 MMBTU/hr, or greater, that were identified in CAMD as not incorporating SCR or SNCR, application of SCR was assumed. The estimated resulting NOx emission rate was calculated as 10% of the lower of the actual 2008 ozone season NOx emission rate or the actual 2009 annual NOx emission rate. A 0.06 lb/MMBTU NOx emission rate floor was also utilized where appropriate.
- For coal-fired units with a heat input rating of 1000 MMBTU/hr or greater, but less than 2000 MMBTU/hr, application of SCR or SNCR was assumed based on the individual unit's 2009 heat input capacity factor. For the applicable units with a heat input capacity factor less than 40%, application of SNCR was assumed and the individual units' NOx emission rates were estimated as described above for coal-fired units with a heat input rating of less than 1000 MMBTU/hr. For the applicable units with a heat input capacity factor of 40% or greater, application of SCR was assumed and the individual units' NOx emission rates were estimated as described above for coal-fired units with a heat input rating of 2000 MMBTU/hour.

For oil and gas-fired boiler EGUs, determination of individual unit NOx emission rates were based on the following criteria:

- If the oil or gas fired boiler's 2008 ozone season NOx emission rate or the 2009 annual NOx emission rate was less than 0.1lb/MMBTU, the lower of the actual 2008 ozone season NOx emission rate or the actual 2009 annual NOx emission rate was selected for the calculation.
- For oil or gas fired boilers that were identified in CAMD (2009 data) as incorporating SCR or SNCR, the individual unit selected NOx emission rate was the lower of the actual 2008 ozone season NOx emission rate or the actual 2009 annual NOx emission rate.
- For oil or gas fired boilers units with a heat input rating less than 1000 MMBTU/hr that were identified in CAMD as not incorporating SCR or SNCR, application of SNCR was assumed. The estimated resulting NOx emission rate was calculated as 50% of the lower of the actual 2008 ozone season NOx emission rate or the actual 2009 annual NOx emission rate. A 0.06 lb/MMBTU NOx emission rate floor was also utilized where appropriate.
- For oil or gas fired boilers with a heat input rating of 2000 MMBTU/hr, or greater, that were identified in CAMD as not incorporating SCR or SNCR, application of SCR was assumed. The estimated resulting NOx emission rate was calculated as 20% of the lower of the actual 2008 ozone season NOx emission rate or the actual 2009 annual NOx emission rate. A 0.06 lb/MMBTU NOx emission rate floor was also utilized where appropriate.
- For oil or gas fired boilers with a heat input rating of 1000 MMBTU/hr or greater, but less than 2000 MMBTU/hr, application of SCR or SNCR was assumed based on the individual unit's 2009 heat input capacity factor. For the applicable units with a heat input capacity factor less than 40%, application of SNCR was assumed and the individual units' NOx emission rates were estimated as described above for oil or gas fired boilers with a heat input rating of less than 1000 MMBTU/hr. For the applicable units with a heat input capacity factor of 40% or greater, application of SCR was assumed and the individual units' NOx emission rates were estimated as described above for oil or gas fired boilers with a heat input rating of 2000 MMBTU/hour.

For combined cycle (CC) and combustion turbine (CT) units, the estimation of individual unit NOx emission rates was based on the following criteria:

- If the CC or CT unit's 2008 ozone season NOx emission rate or the 2009 annual NOx emission rate was less than 0.1 lb/MMBTU, the lower of the actual 2008 ozone season NOx emission rate or the 2009 annual NOx emission rate was selected for the calculation.
- If the CC or CT unit's 2008 ozone season NOx emission rate or the 2009 annual NOx emission rate was 0.1 lb/MMBTU or greater, but the unit was identified in the 2009 CAMD as incorporating water injection, the lower of the actual 2008 ozone season NOx emission rate of the 2009 annual NOx emission rate was selected for the calculation.
- For CC or CT units that were not identified in the 2009 CAMD as incorporating water injection and whose 2008 ozone season NOx emission rate or the 2009 annual NOx emission rate was 0.1 lb/MMBTU or greater, installation of water injection was assumed. The estimated NOx emission rate was calculated as 60% of the lower of the actual 2008 ozone season NOx emission rate or the actual 2009 annual NOx emission rate.

The individual state results for each category of EGU(coal, oil and gas fired, combined cycle and combustion turbine) represent the total NOx mass from all units in each category in that state based on the application of controls applied per the analysis described above. The total 2007 heat input for each category of units in each state is also provided in the table. The average NOx emission rate for each category is calculated based on dividing the total NOx mass for a category of units by the 2007 heat input for the same category of units.

To provide a final summary of each state's average NOx emission rate, the NOx mass from all three categories of units is summed and the 2007 heat rates are summed. The resulting total NOx mass for each state is then divided by the total 2007 heat rate for that state, providing the state's average NOx emission rate. The totals for NOx mass, 2007 heat input and the average NOx emission rate for each category as well as for all units is provided in the last line of Table 1.

Based on the analysis conducted using the methodology and assumptions outlined above, we conclude that a Zone 1 NOx emission cap of 900,000 tons is technologically reasonable and feasible.

Table1. Evaluation of Technologically Feasible NOx Emission Caps in Zone 1 States

State	Projected CC & GT NOx Mass	2007 CC & GT Heat Input	Avg CT & GT NOx Rate	Projected Oil & Gas Boiler NOx Mass	2007 Oil & Gas Boiler Heat Input	Avg Oil & Gas Boiler NOx Rate	Projected Coal Boiler NOx Mass	2007 Coal Boiler Heat Input	Avg Coal Boiler NOx Rate	Projected State Total NOx Mass	2007 Heat Input	Projected State Avg NOx Rate
AL	1036.3	154,990,265	0.0134	0.0	0	0.0000	42,094.60	811,324,802	0.1038	43,130.9	966,315,068	0.0893
AR	547.3	53,772,642	0.0204	205.6	3,314,323	0.1241	8,428.60	280,953,428	0.0600	9,181.5	338,040,393	0.0543
CT	350.4	67,946,074	0.0103	1079.6	18,356,329	0.1176	783.80	26,128,112	0.0600	2,213.8	112,430,515	0.0394
DC	0.0	0	0.0000	30.4	954,663	0.0637	0.00	0	0.0000	30.4	954,663	0.0637
DE	147.0	8,096,240	0.0363	78.4	2,399,392	0.0653	7,106.30	58,261,126	0.2439	7,331.6	68,756,759	0.2133
FL	10061.2	665,887,508	0.0302	8540.1	246,594,216	0.0693	39,345.40	643,610,545	0.1223	57,946.7	1,556,092,270	0.0745
GA	988.3	118,079,523	0.0167	52.9	583,610	0.1814	32,478.60	910,571,688	0.0713	33,519.8	1,029,234,821	0.0651
IL	1115.7	55,506,162	0.0402	1.5	34,086	0.0872	28,063.80	702,391,136	0.0799	29,181.0	757,931,384	0.0770
IN	689.8	29,673,055	0.0465	1.0	25,205	0.0778	58,778.50	1,163,819,112	0.1010	59,469.3	1,193,517,372	0.0997
IA	224.6	22,105,990	0.0203	3.5	103,229	0.0673	20,697.30	411,245,578	0.1007	20,925.3	433,454,796	0.0966
KY	408.7	19,304,511	0.0423	0.0	0	0.0000	42,952.70	980,881,620	0.0876	43,361.4	1,000,186,132	0.0867
LA	1764.7	78,187,967	0.0451	5618.0	154,480,328	0.0727	7,499.30	249,975,212	0.0600	14,882.0	482,643,507	0.0617
ME	210.8	35,632,832	0.0118	135.1	4,139,908	0.0653	0.00	0	0.0000	345.9	39,772,740	0.0174
MD	165.7	4,205,669	0.0788	501.9	15,899,288	0.0631	13,799.00	277,096,366	0.0996	14,466.6	297,201,323	0.0974
MA	780.5	163,996,823	0.0095	1250.0	41,320,847	0.0605	3,986.20	114,775,571	0.0695	6,016.7	320,093,241	0.0376
MI	409.7	25,930,520	0.0316	351.9	10,744,247	0.0655	35,872.40	735,988,367	0.0975	36,634.0	772,663,134	0.0948
MN	670.1	46,572,903	0.0288	40.6	910,150	0.0893	19,263.60	351,982,795	0.1095	19,974.3	399,465,848	0.1000
MS	970.3	123,326,568	0.0157	1487.7	41,906,530	0.0710	6,434.80	197,717,562	0.0651	8,892.8	362,950,660	0.0490
MO	482.2	38,597,707	0.0250	0.0	0	0.0000	38,872.60	762,013,181	0.1020	39,354.8	800,610,888	0.0983
NH	196.8	41,496,351	0.0095	129.1	4,303,867	0.0600	4,107.10	43,847,207	0.1873	4,433.0	89,647,425	0.0989
NJ	828.5	63,322,749	0.0262	198.6	3,568,996	0.1113	8,115.30	77,792,792	0.2086	9,142.4	144,684,537	0.1264
NY	647.5	131,639,601	0.0098	6310.6	194,484,267	0.0649	7,469.80	177,820,167	0.0840	14,427.9	503,944,035	0.0573
NC	782.9	42,394,402	0.0369	0.0	0	0.0000	43,603.10	726,972,856	0.1200	44,386.0	769,367,258	0.1154
OH	426.8	34,832,058	0.0245	0.0	0	0.0000	84,371.50	1,318,717,073	0.1280	84,798.3	1,353,549,131	0.1253
PA	722.2	114,055,430	0.0127	601.9	16,093,526	0.0748	74,362.90	1,097,582,091	0.1355	75,687.0	1,227,731,047	0.1233
RI	192.4	40,358,356	0.0095	0.0	0	0.0000	0.00	0	0.0000	192.4	40,358,356	0.0095
SC	606.7	49,595,479	0.0245	15.8	271,594	0.1162	22,144.90	422,604,920	0.1048	22,767.4	472,471,993	0.0964
TN	138.4	6,617,996	0.0418	0.0	0	0.0000	28,433.40	617,167,282	0.0921	28,571.8	623,785,278	0.0916
TX	7874.8	621,655,930	0.0253	8905.2	293,058,083	0.0608	59,813.50	1,556,315,299	0.0769	76,593.5	2,471,029,311	0.0620
VT	0.0	0	0.0000	0.0	0	0.0000	0.00	0	0.0000	0.0	0	0.0000
VA	1114.6	61,562,406	0.0362	574.6	17,779,211	0.0646	26,249.40	320,736,644	0.1637	27,938.6	400,078,261	0.1397
WV	105.3	3,838,743	0.0548	0.0	0	0.0000	34,924.20	883,289,897	0.0791	35,029.5	887,128,640	0.0790
WI	536.6	36,349,434	0.0295	0.0	0	0.0000	25,224.20	443,712,542	0.1137	25,760.8	480,061,976	0.1073

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Fleet:	35196.4	2,959,531,893	0.0238	36114.1	1,071,325,893	0.0674	825,276.80	16,365,294,973	0.1009	896,587.3	20,396,152,760	0.0879

APPENDIX B
Methodology & Assumptions Used for Installation of SO2 Controls in the Timeline Analysis

SO2 emissions from units listing natural gas or light oil as the primary fuel were not included in evaluating potential SO2 reduction.

For units listed as residual oil-fired, the assumed SO2 reduction methodology of 0.5% sulfur fuel substitution was assumed along with a resulting 0.5 lb/MMBTU SO2 emission rate. If the 2009 actual average SO2 emission rate was lower than 0.5 lb/MMBTU, that lower value was retained for the analysis.

For coal-fired units, assumption of potential SO2 controls was determined as follows:

- For coal-fired units that were identified in CAMD (2009 data) as incorporating FGD, the individual unit selected SO2 emission rate was the actual 2009 annual SO2 emission rate.
- For coal-fired units with a heat input rating less than 1000 MMBTU/hr (approximately 100 MW) that were identified in CAMD as not incorporating any FGD, application of DSI was assumed. The estimated resulting SO2 emission rate was calculated as 60% (40% reduction) of the actual 2009 annual SO2 emission rate. A 0.09 lb/MMBTU SO2 emission rate floor was also utilized where appropriate.
- For coal-fired units with a heat input rating of 2000 MMBTU/hr (approximately 200 MW), or greater, that were identified in CAMD as not incorporating FGD, application of wet FGD was assumed. The estimated resulting SO2 emission rate was calculated as 5% (95% reduction) of the actual 2009 annual SO2 emission rate. A 0.06 lb/MMBTU SO2 emission rate floor was also utilized where appropriate.
- For coal-fired units with a heat input rating of 1000 MMBTU/hr or greater, but less than 2000 MMBTU/hr, and for which the individual unit's 2009 heat input capacity factor was less than 40%, application of dry FGD was assumed. The unit's SO2 emission rate was estimated as 10% (90% reduction) the unit's actual 2009 annual average SO2 emissions rate. A 0.09 lb/MMBTU SO2 emission rate floor was also utilized where appropriate.
- For coal-fired units with a heat input rating of 1000 MMBTU/hr or greater, but less than 2000 MMBTU/hr, and for which the individual unit's 2009 heat input capacity factor was 40% or greater, application of wet FGD was assumed. The unit's SO2 emission rate was estimated as 5% (95% reduction) of the individual unit's 2009 actual average SO2 emission rate. A 0.06 lb/MMBTU SO2 emission rate floor was also utilized where appropriate.

APPENDIX C
Achieving S. 2995 Zone 1 SO2 Caps & 1.3 MMton (2012) and 0.9 MMton (2014) NOx Caps with SO2 as Priority

S.2995 SO2 FGD Retrofit Requirements

In order to attain the S. 2995 2015 annual SO2 mass emissions cap of 2,000,000 tons/yr, it was estimated that it would be necessary to install FGD controls on approximately 165,777 MW of generation. The estimated total boilermaker requirements for FGD retrofit installation is:

165,777 MW * 0.152 BMyr/MW = 25,198 BMyr

Assuming boilermaker construction activities can start in 2011 and installation must be completed in 2014 to achieve the 2015 annual SO2 mass cap, 4-years are available. The estimated average annual boilermaker labor required for FGD retrofit installation is:

25,198 BMyr total/4-yrs = 6,300 BMyr/yr

Utilizing the EPA assumptions for available boilermaker labor, boilermaker availability in excess of FGD retrofit installation is:

9,800 BMyr/yr – 6,300 BMyr/yr = 3,500 BMyr/yr available for NOx control retrofit

On the average for this set of affected EGU's (and the associated assumptions of this review) and assuming that 1-SO2 allowance is the equivalent of 1-ton of SO2 emissions, the boilermaker requirements for this phase of SO2 reduction can be reduced by approximately 1 BMyr for every 200 allowances/year of offsets.

Attaining 2012 NOx Annual Mass Emissions Cap of 1.3 MMton/yr

In order to attain an annual Zone 1 NOx mass emissions cap of 1.3 MMton/yr, it was estimated that approximately 51,500 MW of SCR retrofits would be required.

51,500 MW * 0.175 BMyr/MW = 9,013 BMyr/yr

Assuming construction started by the end of 2010, only one full year would be available for installation of the required SCR retrofits to support the 1.3 MMton/yr Zone 1 NOx mass cap. This implies that 9,013 BMyr would be required for 2011, and this value is in excess of the boilermaker availability utilizing the EPA assumptions and estimates (and assuming FGD retrofits). The requirement for boilermaker SCR retrofits is approximately 32% of the EPA's estimated total 28,000 boilermaker population. Combining the FGD and SCR retrofit boilermaker requirements indicates a total requirement of approximately 15,313 BMyr for 2011, which is approximately 55% of the EPA's estimated total 28,000 boilermaker population.

On the average for this set of affected EGU population (and the associated assumptions of this review) and assuming that 1-NOx allowance is the equivalent of 1-ton of NOx emissions, the boilermaker requirements for this phase of NOx reduction can be reduced by approximately 1 BMyr for every 30 allowances/year of offsets.

One possibility to address the shortfall in the estimated available boilermaker-years/yr is to utilize banked NOx allowances. Based upon the difference between the estimated boilermaker-years required for compliance installation (9013 boilermaker-yr/yr) and the estimated boilermaker-years available using EPA's assumptions (3500 boilermaker-yr/yr), it is estimated that 165,390 allowances/year would be required to make up the shortfall beginning in 2012.

Attaining 2014 NOx Annual Mass Emissions Cap of 0.9 MMton/yr

In order to attain an annual Zone 1 NOx mass emissions cap of 0.9 MMton/yr, it was estimated that an approximate additional 88,693 MW of SCR retrofit and 15,677 MW of SNCR retrofit would be required to be installed.

88,693 MW * 0.175 BMyr/MW = 15,521 BMyr (SCR)
15,677 MW * 0.01 BMyr/MW = 157 BMyr
Total SCR & SNCR requirement = 15,521 + 157 = 15,678 BMyr

Assuming this second phase of NOx reduction technology installation begins in 2012, two full years would be available for the installation of the required retrofit NOx reduction technologies to support the 0.9 MMton/yr Zone 1 NOx mass cap.

15,678 BMyr/2 yr = 7,844 BMyr/yr

This requirement for boilermaker NOx reduction technology retrofits is approximately 28% of the EPA's estimated total 28,000 boilermaker population. Combining the FGD and NOx reduction technology retrofit boilermaker requirements indicates a total requirement of approximately 14,144 BMyr/yr, which is approximately 51% of the EPA's estimated total 28,000 boilermaker population.

On the average for this set of affected EGU population (and the associated assumptions of this review) and assuming that 1-NOx allowance is the equivalent of 1-ton of NOx emissions, the boilermaker requirements for this phase of NOx reduction can be reduced by approximately 1 BMyr for every 26 allowances/year of offsets.

One possibility to address the shortfall in the estimated available boilermaker-years/yr is to utilize banked NOx allowances. Based upon the difference between the estimated boilermaker-years required for compliance installation (7844 boilermaker-yr/yr) and the estimated boilermaker-years available using EPA's assumptions (3500 boilermaker-yr/yr), it is estimated that 112,944 allowances/year would be required to make up the shortfall beginning in 2014. (Note: This assumes that the NOx mass cap limitation is achieved with control retrofits for the 2012 NOx mass cap.)

Year	Estimated Potentially Feasible Annual Zone 1 NOx Mass Emissions (Cap)	Estimated Boilermaker-yrs Required to Attain (NOx Mass Cap)	Estimated Boilermaker-yrs Available (with SO2 as priority)	Estimated Annual Zone 1 NOx Mass Emissions (with SO2 as Priority)	Estimated NOx Allowances Required for Compliance with 1.3-2012/0.9-2014 NOx Caps	Cumulative Estimated NOx Allowances Required for Compliance with 1.3-2012/0.9-2014 NOx Caps
2011	1,574,000	9,013	3,500	1,574,000	N/A	N/A
2012	1,300,000 (cap)	7,844	3,500	1,443,649	143,649	143,649
2013	1,018,000	7,844	3,500	1,353,293	53,293	196,942
2014	900,000 (cap)		3,500	1,234,212	334,212	531,154
2015			4,100	1,132,546	232,546	763,700
2016			4,100	1,010,220	110,220	873,920
2017			4,100	916,303	16,303	890,223
2018				900,000 (cap)		

Assumptions
Total Available Boilermaker Population – 28,000
Percentage of Boilermakers Available for Retrofit – 35% (28,000 x 0.35 = 9,800 BM/yr)
Boilermaker Duty Rate for FGD – 0.152 boilermaker-yr/MW
Boilermaker Duty Rate for SCR – 0.175 boilermaker-yr/MW
Boilermaker Duty Rate for SNCR – 0.01 boilermaker-yr/MW
FGD installations occur first on units with highest 2009 total SO2 mass emissions
SCR/SNCR installations occur first on units with highest 2009 total NOx mass emissions
Individual unit heat inputs equal to 2007 heat inputs were assumed, except for units that did not operate in 2007 and then the individual unit's 2009 heat input were assumed for those units.

APPENDIX D
Achieving S. 2995 Zone 1 SO2 Caps & 1.3 MMton (2012) and 0.9 MMton (2014) NOx Caps with NOx as Priority

Attaining the 2012 Zone 1 NOx Annual Mass Emissions Cap of 1.3 million tons/year

If 51,500 MW of SCR retrofits are required to meet a Zone 1 NOx cap of 1.3 million tons in 2011

Then 51,500 MW * 0.175 BM-yr/MW = 9,013 BM-yr are required to install the necessary controls.

If you assume that all Boilermaker labor needed to perform the SCR installations is contracted first and that the total Boilermaker labor available is 9,800 BM-yr in the 1st year (2011), this would leave only:

9,800 BM-yr - 9,013 BM-yr = 787 BM-yr available for FGD installations in the 1st year (2011)

If the Boilermaker Duty Rate for FGD is 0.152 BM-yr/MW,

Then 787 BM-yr/yr ÷ 0.152 BM-yr/MW = 5,178 MW of FGD that could be installed in the 1st year (2011)

If the estimated average annual boilermaker labor required for FGD retrofit installation is:
25,198 BMyr total/4-yrs = 6,300 BMyr/yr

Then the 1st year shortfall is 6,300 BM-yr - 787 BM-yr = 5,513 BM-yr

If one assumes that 1 SO_2 allowance is the equivalent of 1 ton of SO_2 emissions and the boilermaker requirements for this phase of SO_2 reduction can be reduced by approximately 1 BM-yr for every 200 allowances/year of offsets

Then the maximum <u>annual</u> shortfall in SO_2 reductions in the 1st year (2011) would be:

5,513 BM-yr x 200 SO_2 allowance/BM-yr = 1,102,600 SO_2 allowances.

Assuming all of the above this means that all of the NOx controls required to meet the 2012 NOx cap of 1.3 million tons could be installed and that the SO_2 cap could be met by the installation of 5,178 MW of FGD in conjunction with the use of 1,102,600 SO_2 allowances in the 1st year (2011).

Attaining the 2014 Zone 1 NOx Annual Mass Emissions Cap of 900,000 tons/yr

Assuming that:

The 2nd phase of NOx reduction technology installation begins in 2012;
Two full years (2012 & 2013) would be available for the installation of the required

NOx reduction technologies; and
A total of 15,678 BM-yr are required to support the 900,000 ton/year Zone 1 NOx cap.

Then 15,678 BM-yr/2yr = 7,844BM-year are needed in 2012 and an additional 7,844BM-year are needed in 2012   Applying the same calculation methodology used above for Phase 1, all of the required NOx reduction technologies could be installed and an additional 868, 800 tons of SO_2 allowances would be needed each year in 2012 and 2013 in order to supplement the amount of FGD retrofits required to meet the annual SO_2 cap.   Since all of the NOx reduction retrofit technologies required to meet the 2nd phase NOx cap could be installed by the end of 2013, no additional boilermaker labor would be needed in 2014 for NOx control retrofits. Thus all of the 9800 BM-yr would be available for installing any additional FGD retrofits required to meet the annual SO_2 cap in future years.

The following table summarizes the calculations used to estimate the impact of the manpower constraints on achieving the OTC/CAPA Zone 1 NOx and SO_2 caps.

Year	**Total Available (BM-yr)**	**NOx (SCR) retrofits Required (BM-yr)**	**Difference**	**SO_2 (FGD) Retrofits Required (BM-yr)**	**SO_2 (FGD) Retrofits Available (BM-yr)**	**SO_2 (FGD) Retrofits Shortfall (BM-yr)**	**SO_2 Allowances Needed to Make up the Shortfall**
2011	9,800	9,013	787	6,300	787	5,513	1,102,600
2012	9,800	7,844	1,956	6,300	1,956	4,344	868,800
2013	9,800	7,844	1,956	6,300	1,956	4,344	868,800
2014	9,800	0	9,800	6,300	9,800	-	-

Assumptions
- Total Available Boilermaker Population – 28,000
- Percentage of Boilermakers Available for Retrofit – 35% (28,000 x 0.35 = 9,800 BM/yr)
- Boilermaker Requirement for 2011 SCR/SNCR priority retrofits = 9,013 BM/yr
- Boilermaker Availability for 2011 FGD retrofits = 787 BM/yr
- Boilermaker Requirement for 2012-2013 SCR/SNCR priority retrofits = 7,844 BM/yr
- Boilermaker Availability for 2012-2013 FGD retrofits – 1,956 BM/yr
- Boilermaker Requirement for 2014 & after SCR/SNCR retrofits = 0
- Boilermaker Availability for 2014 & after FGD retrofits == 9,800 BM/yr
- Boilermaker Duty Rate for FGD – 0.152 boilermaker-yr/MW
- Boilermaker Duty Rate for SCR – 0.175 boilermaker-yr/MW
- Boilermaker Duty Rate for SNCR – 0.01 boilermaker-yr/MW
- FGD installations occur first on units with highest 2009 total SO2 mass emissions
- SCR/SNCR installations occur first on units with highest 2009 total NOx mass emissions
- Individual unit heat inputs equal to 2007 heat inputs were assumed, except for units that did not operate in 2007 and then the individual unit’s 2009 heat input were assumed for those units.

APPENDIX 4

OTC Table 1: Allocations vs IPM vs Actuals

State	Proj Base Case - Ozone Season NOx Mass (tons)	CATR Ozone Season Allocation	Projected Ozone Season NOx Mass - TR_NOX_OS_500 (tons) - from Budgets and Allocations - Detailed Unit-Level Data	Emission Rate from TR_NOX_ OS_500	2008 Emissions (from CAMD)	2008 Emission Rate	2009 Emissions - (from CAMD)	2009 Emission Rate	Emissions - IPM (Col D) minus 2009	Emission Rate - IPM minus 2009
Alabama	29,938	29,738	27,103	0.083	36923	0.171	20549	0.110	6,554	-0.027
Arkansas	20,558	16,660	11,503	0.082	16561	0.215	16285	0.191	-4,782	-0.109
Connecticu	3,405	1,315	3,413	0.048	1398	0.066	447	0.028	2,966	0.020
Delaware	1,944	2,450	2,056	0.102	3194	0.242	447	0.182	1,609	-0.080
D C	0	105	0	0.000	105	0.257	30	0.260	-30	-0.260
Florida	101,281	56,939	68,274	0.138	75292	0.195	41400	0.110	26,874	0.028
Georgia	35,197	32,144	20,212	0.064	33430	0.149	27035	0.130	-6,823	-0.066
Illinois	24,347	23,570	24,206	0.053	31721	0.140	27041	0.129	-2,835	-0.076
Indiana	50,918	49,987	48,439	0.159	56120	0.204	44308	0.186	4,131	-0.027
Kansas	30,557	21,433	16,381	0.200	22099	0.256	20409	0.243	-4,028	-0.043
Kentucky	30,988	30,908	29,315	0.136	39257	0.187	32261	0.165	-2,946	-0.029
Louisiana	21,703	21,220	16,651	0.114	23613	0.162	20565	0.145	-3,914	-0.032
Maryland	8,898	7,232	8,694	0.083	9044	0.148	7044	0.136	1,650	-0.053
Michigan	29,643	28,253	30,018	0.113	36400	0.223	32464	0.210	-2,446	-0.096
Mississippi	16,889	16,530	8,274	0.113	21076	0.245	14640	0.174	-6,366	-0.061
New Jersey	7,066	5,269	7,275	0.051	4281	0.088	2264	0.056	5,011	-0.005
New York	15,686	11,090	16,174	0.061	13075	0.098	9427	0.086	6,747	-0.025
North Caro	27,025	23,539	26,928	0.090	23402	0.134	16575	0.112	10,353	-0.022
Ohio	42,004	40,661	44,049	0.121	52444	0.188	36066	0.151	7,983	-0.030
Oklahoma	43,095	37,087	21,901	0.161	36426	0.240	34054	0.225	-12,153	-0.064
Pennsylvan	50,973	48,271	51,284	0.104	51581	0.195	41422	0.159	9,862	-0.055
South Caro	15,842	15,222	15,542	0.067	15641	0.141	8977	0.093	6,565	-0.026
Tennessee	11,585	11,575	11,976	0.063	18019	0.138	10828	0.123	1,148	-0.060
Texas	78,829	75,574	61,460	0.083	74148	0.100	68819	0.095	-7,359	-0.013
Virginia	17,228	12,608	15,683	0.090	14972	0.179	10275	0.145	5,408	-0.055
West Virgin	23,988	22,234	23,643	0.115	25079	0.137	13602	0.101	10,041	0.014
	739,585	641,614	610,454		735,301		557,234			

APPENDIX 5

OTC Table 2: 2014 vs 2012 SO2 Allocations

				Allocations (Tons)					Direct Control Alternative -- Allowable Rate (Lbs/mmBtu)			
Plant Name	ORIS	Unit	State Name	2012 SO2 Allocation	2014 SO2 Allocation	SO2 increase	Annual NOx Allocation	Ozone Season NOx Allocation	2012 SO2 Rate	2014 SO2 Rate	Annual NOx Rate	Ozone Season NOx Rate
Iatan	6065	1	Missouri	978	11,600	-10,622	1,585	0	0.059	0.536	0.076	0.000
Mountaineer	6264	1	West Virginia	2,721	12,800	-10,079	2,821	1,415	0.079	0.299	0.060	0.067
Mitchell	3948	1	West Virginia	1,682	9,485	-7,803	1,210	527	0.070	0.337	0.051	0.051
Mitchell	3948	2	West Virginia	1,667	9,405	-7,738	1,397	612	0.070	0.337	0.052	0.052
Paradise	1378	3	Kentucky	3,320	9,807	-6,487	3,465	1,404	0.121	0.264	0.093	0.931
Columbia	8023	1	Wisconsin	2,877	8,757	-5,880	2,680	0	0.541	0.504	0.133	0.000
Conesville	2840	4	Ohio	266	5,539	-5,273	1,369	536	0.038	0.201	0.058	0.582
Oswego Harbor Pow	2594	5	New York	251	4,987	-4,736	878	316	1.043	0.977	0.039	0.388
Thomas Hill	2168	MB3	Missouri	8,869	13,146	-4,277	2,822	0	0.417	0.521	0.127	0.000
Gibson	6113	1	Indiana	1,487	4,572	-3,085	1,337	586	0.080	0.199	0.058	0.582
Gibson	6113	2	Indiana	1,529	4,583	-3,054	1,340	587	0.085	0.199	0.058	0.582
Keystone	3136	1	Pennsylvania	3,385	6,103	-2,718	1,274	559	0.108	0.195	0.041	0.408
Keystone	3136	2	Pennsylvania	3,298	5,946	-2,648	1,230	540	0.108	0.195	0.040	0.404
Harding Street	990	70	Indiana	1,638	4,132	-2,494	907	397	0.131	0.265	0.058	0.582
Cayuga	1001	1	Indiana	934	3,417	-2,483	4,150	1,816	0.075	0.199	0.242	2.417
Mitchell	727	3	Georgia	1,983	4,355	-2,372	1,840	883	1.557	0.800	0.608	0.581
Kincaid Generation	876	1	Illinois	8,370	10,565	-2,195	1,231	512	0.435	0.512	0.059	0.059
Ghent	1356	4	Kentucky	1,214	3,359	-2,145	468	189	0.079	0.203	0.029	0.287
Crawford	867	8	Illinois	3,384	5,461	-2,077	982	418	0.495	0.488	0.141	0.125
Gibson	6113	3	Indiana	2,439	4,490	-2,051	1,313	575	0.118	0.199	0.058	0.582
Gibson	6113	4	Indiana	2,997	5,014	-2,017	1,333	584	0.184	0.219	0.058	0.582
Hatfields Ferry Pow	3179	3	Pennsylvania	3,522	5,495	-1,973	3,593	1,401	0.198	0.301	0.202	2.018
Joliet 29	384	72	Illinois	2,925	4,851	-1,926	761	401	0.436	0.510	0.128	0.124
Hammond	708	4	Georgia	628	2,517	-1,889	2,299	1,114	0.048	0.126	0.166	0.166
Vermilion	897	2	Illinois	1,570	3,438	-1,868	774	336	0.458	0.486	0.213	0.239
Cayuga	1001	2	Indiana	1,771	3,466	-1,695	4,203	1,839	0.126	0.199	0.241	2.413
PPL Montour	3149	2	Pennsylvania	1,569	3,253	-1,684	1,481	649	0.056	0.117	0.053	0.532
R M Schahfer	6085	15	Indiana	6,840	8,507	-1,667	3,129	1,369	0.534	0.529	0.157	1.571
Tanners Creek	988	U1	Indiana	931	2,581	-1,650	1,158	503	1.035	0.610	0.275	2.745
Joliet 9	874	5	Illinois	3,358	4,974	-1,616	3,497	1,168	0.425	0.486	0.340	0.319
Fisk Street	886	19	Illinois	4,153	5,715	-1,562	1,213	589	0.486	0.488	0.126	0.142
Bruce Mansfield	6094	3	Pennsylvania	6,593	8,129	-1,536	1,702	691	0.225	0.263	0.058	0.582
Lansing	1047	4	Iowa	4,539	6,074	-1,535	566	0	0.627	0.557	0.058	0.000
Thomas Hill	2168	MB1	Missouri	2,083	3,611	-1,528	675	0	0.391	0.536	0.121	0.000
Petersburg	994	2	Indiana	1,378	2,822	-1,444	968	423	0.113	0.170	0.058	0.582
Ghent	1356	1	Kentucky	2,221	3,653	-1,432	794	346	0.139	0.214	0.050	0.504
Northport	2516	1	New York	588	1,991	-1,403	1,295	544	0.128	0.230	0.136	1.356
Shawnee	1379	1	Kentucky	2,830	4,216	-1,386	1,028	420	0.715	0.943	0.201	2.010
Killen Station	6031	2	Ohio	1,402	2,780	-1,378	1,127	494	0.068	0.144	0.058	0.582
Kincaid Generation	876	2	Illinois	9,157	10,528	-1,371	1,192	475	0.448	0.512	0.058	0.058
Thomas Hill	2168	MB2	Missouri	4,528	5,856	-1,328	1,600	0	0.426	0.536	0.203	0.000
Joliet 29	384	82	Illinois	3,572	4,851	-1,279	896	362	0.432	0.510	0.111	0.107
Will County	884	3	Illinois	3,074	4,331	-1,257	1,002	423	0.440	0.510	0.125	0.110
Lake Road	2098	6	Missouri	1,055	2,256	-1,201	1,184	0	0.678	0.489	0.655	0.000
Columbia	8023	2	Wisconsin	7,292	8,459	-1,167	2,570	0	0.541	0.504	0.132	0.000
Will County	884	1	Illinois	1,464	2,604	-1,140	403	177	0.425	0.510	0.077	0.077
Bay Shore	2878	1	Ohio	2,098	3,225	-1,127	464	202	0.299	0.663	0.090	0.902
Will County	884	2	Illinois	1,628	2,745	-1,117	360	139	0.430	0.510	0.079	0.079
O H Hutchings	2848	H-1	Ohio	37	1,152	-1,115	523	227	1.197	0.582	0.264	2.639
Dunkirk Generating	2554	4	New York	2,451	3,550	-1,099	469	204	0.590	0.498	0.066	0.657
Hatfields Ferry Pow	3179	1	Pennsylvania	3,463	4,559	-1,096	5,404	2,186	0.195	0.242	0.304	3.036
Ashtabula	2835	7	Ohio	2,460	3,526	-1,066	994	432	0.652	0.483	0.136	1.362
Potomac River	3788	5	Virginia	332	1,372	-1,040	284	130	0.321	0.343	0.220	0.244
Prairie Creek	1073	4	Iowa	1,240	2,273	-1,033	1,749	0	0.559	0.509	0.000	0.000
O H Hutchings	2848	H-2	Ohio	24	1,050	-1,026	470	204	1.198	0.582	0.260	2.602
Ames Electric Servi	1122	8	Iowa	487	1,511	-1,024	605	0	0.343	0.509	0.382	0.000
Cardinal	2828	1	Ohio	2,975	3,981	-1,006	789	319	0.176	0.199	0.042	0.417
O H Hutchings	2848	H-6	Ohio	221	1,224	-1,003	484	210	1.224	0.582	0.230	2.298

				Allocations (Tons)					Direct Control Alternative -- Allowable Rate (Lbs/mmBtu)			
Plant Name	ORIS	Unit	State Name	2012 SO2 Allocation	2014 SO2 Allocation	SO2 increase	Annual NOx Allocation	Ozone Season NOx Allocation	2012 SO2 Rate	2014 SO2 Rate	Annual NOx Rate	Ozone Season NOx Rate
O H Hutchings	2848	H-5	Ohio	234	1,219	-985	482	209	1.202	0.582	0.230	2.298
McIntosh	6124	1	Georgia	2,992	3,973	-981	1,919	0	1.103	0.758	0.494	0.000
Northport	2516	2	New York	1,839	2,804	-965	224	82	0.334	0.323	0.021	0.213
Chesapeake	3803	1	Virginia	2,403	3,364	-961	809	272	0.865	0.803	0.267	0.267
Milton L Kapp	1048	2	Iowa	3,369	4,327	-958	469	0	0.635	0.509	0.110	0.000
Chesapeake	3803	2	Virginia	2,639	3,591	-952	924	314	0.859	0.798	0.296	0.296
Kenneth C Colemar	1381	C1	Kentucky	624	1,569	-945	1,646	704	0.138	0.270	0.302	3.024
Bremo Bluff	3796	3	Virginia	1,511	2,452	-941	1,137	337	1.496	0.858	0.645	0.687
Bailly	995	8	Indiana	2,196	3,125	-929	1,361	548	0.242	0.247	0.108	1.075
Potomac River	3788	3	Virginia	374	1,303	-929	278	148	0.321	0.343	0.241	0.235
O H Hutchings	2848	H-3	Ohio	219	1,120	-901	443	192	1.163	0.582	0.230	2.298
New Madrid	2167	2	Missouri	6,408	7,293	-885	1,527	0	0.382	0.536	0.084	0.000
Earl F Wisdom	1217	1	Iowa	20	850	-830	274	0	2.069	0.613	0.535	0.000
Potomac River	3788	4	Virginia	516	1,339	-823	458	152	0.348	0.343	0.271	0.243
Roxboro	2712	3A	North Carolina	818	1,624	-806	1,399	603	0.060	0.119	0.134	0.134
Wabash River	1010	1A	Indiana	221	1,007	-786	430	188	0.105	0.159	0.068	0.679
Roxboro	2712	4A	North Carolina	795	1,567	-772	867	343	0.062	0.122	0.076	0.076
Roxboro	2712	1	North Carolina	770	1,530	-760	828	385	0.060	0.119	0.079	0.079
Trimble County	6071	1	Kentucky	1,499	2,257	-758	599	261	0.078	0.162	0.047	0.466
Roxboro	2712	3B	North Carolina	767	1,524	-757	1,356	613	0.060	0.119	0.135	0.135
Robert A Reid	1383	R1	Kentucky	1,136	1,872	-736	734	284	4.548	0.887	0.312	3.124
Roxboro	2712	4B	North Carolina	746	1,470	-724	782	303	0.062	0.122	0.076	0.076
Crawford	867	7	Illinois	3,071	3,793	-722	874	365	0.491	0.488	0.122	0.123
Potomac River	3788	1	Virginia	185	907	-722	109	58	0.371	0.327	0.233	0.213
Kenneth C Colemar	1381	C2	Kentucky	854	1,569	-715	1,671	715	0.138	0.270	0.307	3.069
Dunkirk Generating	2554	3	New York	2,846	3,537	-691	468	203	0.587	0.498	0.066	0.657
Asheville	2706	2	North Carolina	414	1,095	-681	322	121	0.062	0.154	0.058	0.062
Potomac River	3788	2	Virginia	107	755	-648	64	41	0.333	0.327	0.223	0.213
Mayo	6250	1A	North Carolina	774	1,415	-641	716	308	0.060	0.102	0.066	0.066
Mayo	6250	1B	North Carolina	774	1,415	-641	592	240	0.060	0.102	0.067	0.067
O H Hutchings	2848	H-4	Ohio	433	1,073	-640	424	184	1.168	0.582	0.230	2.298
Lima Energy	55635	1	Ohio	526	1,150	-624	1,135	497	0.030	0.065	0.064	0.640
Kenneth C Colemar	1381	C3	Kentucky	1,003	1,621	-618	1,713	733	0.156	0.270	0.304	3.044
Tanners Creek	988	U2	Indiana	1,912	2,514	-602	1,127	490	1.050	0.610	0.274	2.743
Vermilion	897	1	Illinois	810	1,383	-573	491	225	0.451	0.486	0.211	0.233
Roxboro	2712	2	North Carolina	1,493	2,061	-568	1,193	485	0.063	0.087	0.055	0.055
Conesville	2840	6	Ohio	2,144	2,702	-558	2,808	1,226	0.171	0.216	0.270	2.700
Bay Shore	2878	2	Ohio	1,443	1,972	-529	1,527	592	0.637	0.493	0.342	3.424
Hennepin Power Sta	892	2	Illinois	3,651	4,170	-519	892	443	0.500	0.486	0.134	0.141
Bowen	703	1BLR	Georgia	2,742	3,245	-503	1,233	606	0.130	0.126	0.056	0.056
Conesville	2840	5	Ohio	2,257	2,733	-476	2,855	1,246	0.185	0.216	0.271	2.713
Bowen	703	2BLR	Georgia	1,010	1,466	-456	1,422	581	0.045	0.054	0.055	0.055
Dubuque	1046	1	Iowa	473	925	-452	637	0	0.615	0.557	0.601	0.000
Wood River	898	5	Illinois	6,171	6,616	-445	1,997	857	0.462	0.486	0.151	0.156
Lansing	1047	3	Iowa	480	923	-443	597	0	0.686	0.557	0.580	0.000
Meredosia	864	03	Illinois	79	511	-432	254	76	4.347	0.486	0.522	0.489
Dallman	963	32	Illinois	455	879	-424	279	130	0.167	0.234	0.086	0.086
Port Jefferson	2517	4	New York	498	902	-404	361	151	0.296	0.230	0.083	0.833
Tanners Creek	988	U3	Indiana	3,127	3,491	-364	1,586	689	1.057	0.610	0.278	2.780
Sutherland	1077	3	Iowa	944	1,303	-359	1,021	0	0.874	0.509	0.515	0.000
Waukegan	883	17	Illinois	1,565	1,921	-356	315	138	0.470	0.503	0.000	0.727
East Bend	6018	2	Kentucky	2,038	2,387	-349	1,113	488	0.095	0.108	0.050	0.504
Streeter Station	1131	7	Iowa	521	858	-337	1,069	0	1.264	0.542	0.000	0.000
Dubuque	1046	5	Iowa	337	666	-329	625	0	0.625	0.557	0.731	0.000
Meredosia	864	04	Illinois	184	511	-327	247	98	4.338	0.486	0.495	0.464
Clover	7213	2	Virginia	971	1,298	-327	4,412	1,817	0.066	0.078	0.275	0.275
Clover	7213	1	Virginia	965	1,278	-313	4,313	1,845	0.057	0.078	0.272	0.272
Bay Shore	2878	3	Ohio	1,879	2,189	-310	1,606	697	0.615	0.493	0.336	3.356

				Allocations (Tons)					Direct Control Alternative -- Allowable Rate (Lbs/mmBtu)			
Plant Name	ORIS	Unit	State Name	2012 SO2 Allocation	2014 SO2 Allocation	SO2 increase	Annual NOx Allocation	Ozone Season NOx Allocation	2012 SO2 Rate	2014 SO2 Rate	Annual NOx Rate	Ozone Season NOx Rate
Miami Fort	2832	7	Ohio	2,475	2,785	-310	879	355	0.130	0.163	0.051	0.514
Joppa Steam	887	4	Illinois	2,633	2,938	-305	843	343	0.622	0.493	0.115	0.111
Walter Scott Jr. Ene	1082	4	Iowa	1,876	2,158	-282	1,510	0	0.071	0.079	0.057	0.000
Ames Electric Servi	1122	7	Iowa	433	712	-279	549	0	0.397	0.509	0.359	0.000
Muscatine Plant #1	1167	9	Iowa	105	372	-267	779	0	0.018	0.072	0.124	0.000
Riverside	1081	9	Iowa	2,067	2,327	-260	795	0	0.645	0.509	0.221	0.000
Northport	2516	4	New York	1,734	1,991	-257	214	78	0.237	0.230	0.020	0.204
Wabash River	1010	1	Indiana	221	448	-227	191	84	0.105	0.159	0.068	0.679
Prairie Creek	1073	3	Iowa	693	918	-225	979	0	0.591	0.509	0.000	0.000
Port Jefferson	2517	3	New York	646	869	-223	326	137	0.285	0.230	0.078	0.783
Northport	2516	3	New York	1,544	1,755	-211	1,362	572	0.290	0.230	0.162	1.618
Yates	728	Y1BR	Georgia	175	376	-201	1,050	423	0.072	0.092	0.359	0.282
E D Edwards	856	2	Illinois	3,467	3,648	-181	1,870	832	0.443	0.395	0.223	0.226
Mecklenburg Power	52007	BLR1	Virginia	153	322	-169	363	114	0.125	0.117	0.271	0.263
Mecklenburg Power	52007	BLR2	Virginia	153	322	-169	463	142	0.115	0.117	0.286	0.284
Hopewell	10771	1	Virginia	8	170	-162	203	73	0.020	0.117	0.263	0.263
Hopewell	10771	2	Virginia	8	170	-162	205	73	0.020	0.117	0.270	0.270
Wood River	898	4	Illinois	1,746	1,906	-160	447	229	0.509	0.486	0.136	0.144
Asheville	2706	1	North Carolin	483	627	-144	252	115	0.067	0.087	0.044	0.044
Southampton Powe	10774	1	Virginia	41	173	-132	352	121	0.059	0.065	0.381	0.371
Hutsonville	863	05	Illinois	999	1,128	-129	646	232	0.568	0.486	0.215	0.207
Pleasants Power St	6004	1	West Virginia	3,859	3,986	-127	2,031	800	0.169	0.165	0.087	0.087
Pleasants Power St	6004	2	West Virginia	3,826	3,952	-126	1,498	639	0.169	0.165	0.077	0.077
Hammond	708	2	Georgia	157	280	-123	520	225	0.070	0.066	0.201	0.177
Dallman	963	34	Illinois	1,487	1,610	-123	333	145	0.257	0.244	0.058	0.577
Walter Scott Jr. Ene	1082	1	Iowa	896	1,012	-116	561	0	0.556	0.542	0.340	0.000
Dallman	963	31	Illinois	607	720	-113	254	110	0.659	0.234	0.000	0.000
Hennepin Power St	892	1	Illinois	1,313	1,408	-95	291	110	0.486	0.486	0.136	0.142
Mitchell Power Stati	3181	33	Pennsylvania	508	599	-91	2,227	865	0.058	0.055	0.255	2.551
Chesterfield	3797	6	Virginia	1,489	1,576	-87	687	344	0.066	0.065	0.037	0.037
Burlington	1104	1	Iowa	4,081	4,154	-73	1,195	0	0.579	0.509	0.168	0.000
Grant Town Power I	10151	BLR1A	West Virginia	499	570	-71	202	84	0.373	0.364	0.083	0.083
Pulliam	4072	7	Wisconsin	1,197	1,263	-66	1,132	0	0.534	0.512	0.374	0.000
Altavista Power Sta	10773	1	Virginia	17	82	-65	153	55	0.037	0.065	0.272	0.274
Altavista Power Sta	10773	2	Virginia	18	82	-64	154	55	0.038	0.065	0.271	0.271
Warrick	6705	3	Indiana	535	596	-61	1,865	810	0.079	0.106	0.332	3.322
Pulliam	4072	6	Wisconsin	1,108	1,169	-61	1,718	0	0.534	0.512	0.711	0.000
Buchanan County G	55738	1	Virginia	0	56	-56	6	3	0.001	0.072	0.079	0.073
Buchanan County G	55738	2	Virginia	0	56	-56	6	3	0.001	0.072	0.080	0.077
Weston	4078	2	Wisconsin	1,323	1,376	-53	1,105	0	0.567	0.536	0.340	0.000
Pulliam	4072	5	Wisconsin	836	882	-46	1,345	0	0.534	0.512	0.736	0.000
Weston	4078	1	Wisconsin	1,142	1,188	-46	392	0	0.567	0.536	0.248	0.000
TES Filer City Static	50835	2	Michigan	151	186	-35	332	144	0.181	0.170	0.398	3.976
Miami Fort	2832	8	Ohio	2,505	2,539	-34	909	368	0.142	0.152	0.054	0.543
Dunkirk Generating	2554	1	New York	1,513	1,545	-32	419	168	0.577	0.499	0.144	1.440
Pulliam	4072	4	Wisconsin	568	599	-31	763	0	0.534	0.512	0.000	0.000
Kraft	733	1	Georgia	1,523	1,552	-29	943	538	1.197	0.864	0.604	0.611
Grant Town Power I	10151	BLR1B	West Virginia	503	531	-28	200	81	0.373	0.364	0.085	0.085
AES Greenidge LLC	2527	6	New York	375	401	-26	237	103	0.167	0.098	0.058	0.575
Walter Scott Jr. Ene	1082	2	Iowa	2,070	2,091	-21	369	0	0.627	0.542	0.132	0.000
Lake Shore	2838	18	Ohio	1,926	1,944	-18	1,070	465	0.674	0.210	0.129	1.286
TES Filer City Static	50835	1	Michigan	163	172	-9	372	162	0.178	0.168	0.407	4.073
G G Allen	2718	4	North Carolin	607	612	-5	1,265	672	0.070	0.065	0.173	0.187
G G Allen	2718	3	North Carolin	583	588	-5	1,256	658	0.070	0.065	0.173	0.179
G G Allen	2718	5	North Carolin	600	604	-4	1,585	746	0.070	0.065	0.201	0.201
Shiras	1843	3	Michigan	136	138	-2	187	81	0.084	0.079	0.116	1.164
Eastlake	2837	3	Ohio	2,042	2,043	-1	663	257	0.969	0.510	0.148	1.484

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Vermont
Virginia

Anna Garcia
Executive Director

444 N. Capitol St. NW
Suite 638
Washington, DC 20001
(202) 508-3840
FAX (202) 508-3841
e-mail: ozone@otcair.org

September 10, 2009

The Honorable Lisa P. Jackson, Administrator
U.S. Environmental Protection Agency
Ariel Rios Building
1200 Pennsylvania Avenue, NW
Mail Code 1101A
Washington, DC 20460

Dear Administrator Jackson:

On September 2, 2009, 17 states within the Ozone Transport Commission (OTC) and the Lake Michigan Area Directors Consortium (LADCO) submitted a letter to you containing recommendations for the Environmental Protection Agency (EPA) to consider as it develops a replacement rule for the Clean Air Interstate Rule (CAIR replacement). The OTC and LADCO States reached consensus on many critical issues, including the creation of a three-step framework to address the requirement of section 110(a)(2)(D) of the Clean Air Act (CAA). Building on the OTC and LADCO consensus, this letter provides EPA with additional recommendations related to several aspects of the joint OTC-LADCO letter of September 2nd based on OTC's 15 years of experience addressing the scientific phenomenon of air pollutant transport and its impact on public health.

Achieving the ozone and $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS) is a challenge and widespread regional reductions are a very important piece in the solution to this puzzle. The U.S. Court of Appeals for the District of Columbia Circuit found that CAIR failed in at least two important ways: (1) it did not ensure sufficient reductions from each state; and (2) the schedule did not mesh with the attainment deadlines. The additional recommendations OTC is providing are intended to address both issues. By combining regional and state caps, electricity generating unit (EGU) emission reductions will be achieved cost-effectively throughout the region while ensuring that each State's emissions are reduced significantly. To the extent possible, given labor and supply constraints, emissions reductions need to occur three years prior to the attainment deadlines in order to provide the maximum benefit in a timely manner.

OTC recognizes that the attainment deadlines for the 75 ppb ozone NAAQS, or a more stringent ozone NAAQS, will be a function of the yet to be adopted nonattainment classification levels. OTC further suggests that EPA's rules also address a longer time period, including between 2017 and about 2025, to address longer-term air quality improvement needs and the very substantial emission reductions necessary to attain and maintain the air quality standards.

OTC appreciates the efforts put forth by EPA to work with all interested stakeholders in developing a CAIR replacement rule based on sound science. OTC further acknowledges that air pollutant transport within the OTC region is a significant issue that EPA should also address. The CAIR replacement rule should also recognize that our planning processes continue to evolve in the face of ever-tightening standards and newly uncovered air quality concerns, such as the impact of peaking unit emissions on high electricity demand days (HEDD). As such, OTC recommends that EPA propose measures to address HEDD emissions in the CAIR replacement rule.

Our recommendations are provided below in three parts. OTC considers these recommendations feasible, practicable and operable within the framework of the existing Clean Air Act, all of which facilitate a rapid adoption process as directed by the D.C. Circuit Court of Appeals in remanding CAIR. The CAIR replacement rule offers an opportunity for transformational change over incremental improvement. Providing regulatory certainty to America's electric generating sector promotes transformational change through business decisions that support our air quality goals. A summary of the technical analyses conducted by the OTC States and provided as support documentation for the recommendations provided in this letter and the September 2, 2009 letter is attached to support these recommendations.

A. Achievable EGU Limitations

The OTC States recommend that EPA consider a comprehensive, multi-layered, hybrid approach for obtaining further reductions from EGUs. This hybrid approach combines state and regional caps with phased-in performance standards to cost-effectively reduce nitrogen oxide (NOx) and sulfur dioxide (SO_2) emissions. The components of this strategy (enforceable conditions, state-by-state reductions, regional trading caps/program and phased performance standards), should coordinate with each other and other EGU control initiatives such as federal MACT standards and greenhouse gas reduction programs.

A national strategy for EGUs should be implemented in phases. The first phase should combine federally enforceable NOx and SO_2 reductions from each state with a regional trading program. A later phase should include performance standards to achieve continuing reductions from the EGU sector over the course of the regulatory time frame for implementation of the 2008 ozone and 2006 $PM_{2.5}$ NAAQS.

Timing is essential to meet attainment obligations. Three years of data are needed to demonstrate attainment; therefore reductions are needed three years prior to the attainment deadline. While we recognize that full implementation of all controls may not be achieved in that time frame, it is essential that enforceable mechanisms be provided to lock in controls that are achievable. The OTC-LADCO submission reflects the participating states' agreement on state-specific caps that would be applicable no later than 2017. Years prior to 2017 may be critical for many states to demonstrate attainment with the applicable NAAQS. The OTC States seek to work with EPA to develop mechanisms for achieving interim reductions in the 2012-16 time period, including the possibility of interim state-specific caps in addition to a regional cap-and-trade program.

Since CAIR was not sufficient for attaining and maintaining the 1997 ozone NAAQS, EPA will need to make the limits in the CAIR replacement rule stricter to enable compliance with the recently revised ozone and PM NAAQS and any tighter standards that EPA enacts after reconsideration of those standards. The state caps are also necessary to ensure that each State contributes fully to the needed reductions.

Specifically, the OTC States propose that EPA include phased state-by-state reductions, complementary regional emission trading caps as early as possible (but no later than 2014), and performance standards as follows:

1. State-by-State Reductions

The September 2, 2009 letter recommends the implementation of state caps by no later than 2017 that reflect the emission rates that would be achieved through installation of SCR and FGD controls on all coal-fired EGUs of 100 MW or larger in all significantly contributing states. In addition, the participating states recommend in that letter a number of interim measures including operation and optimization of all controls currently in place or being installed to meet other requirements, and installation and operation of all feasible, low capital cost NOx controls such as selective non-catalytic reduction (SNCR) and low NOx burners (LNB) not currently installed or in use on existing EGUs on a unit basis by 2015.

The OTC States recommend that EPA analyze and determine the state-by-state reductions needed prior to 2017 in order to address CAA Section 110(a)(2)(D) requirements to address interstate transport from EGUs within the NAAQS timeframe. The OTC States see interim state-by-state reductions prior to 2017 as a key part of addressing the Court of Appeals concerns over what is needed to satisfy the requirements of CAA Section 110(a)(2)(D).

2. Regional Trading Programs for NOx and SO_2.

As explained in the September 2, 2009 submission, the second key element of the OTC-LADCO agreed framework for a CAIR replacement rule is the implementation of regional trading programs for both NOx and SO_2, to complement the state-by-state caps described above. The OTC States recommend that EPA consider the following in developing the regional caps:

- The new regional caps should be implemented as early as possible and set at a level that will drive deeper regional NOx and SO_2 reductions than the regional reductions that would result from the implementation of the state-by-state caps by themselves. This pairing of state-by-state caps with an aggressive regional trading program will guarantee specific reductions in each state while also using market forces to further reduce regional emissions at lowest cost.
- OTC's analysis (attached) and the analysis that EPA recently prepared for Senator Carper show that stringent regional trading caps for NOx and SO_2, implemented as early as possible (but no later than 2014), would provide significant public health benefits that substantially outweigh the costs.
- Banking and inter-state trading would continue to be allowed in the regional trading program.

- To be creditable under Section 110(a)(2)(D), controls installed in response to the regional trading program should be made federally enforceable through an appropriate mechanism.

3. Performance Standards

We understand that EPA is also considering a hybrid approach in its CAIR replacement rule involving regional emissions trading and unit-specific performance standards (cite: July 9, 2009, testimony by R. McCarthy before the Subcommittee on Clean Air and Nuclear Safety, Committee on Environment and Public Works, U.S. Senate).

The OTC States request that EPA work with the states to develop and phase in unit-specific performance standards that owners of fossil fuel-fired units should comply with between 2017 and 2025, or earlier if EPA's technical analysis demonstrates that an earlier date is reasonable. Performance standards should either be output-based or transition to output-based standards to reward efficiency. Such performance standards will give regulatory certainty to EGU owners and encourage transformational change in the energy market. In developing these performance standards:

- EPA should consider fuels, types and sizes of EGUs, the timing of other requirements included in this and the September 2, 2009 letter, cost-effectiveness and the pollution control equipment already in place on the existing fleet of EGUs.
- EPA should phase-in the performance standards to maximize efficiency and minimize costs to affected sources. For example:
    - The performance standards for coal-fired units greater than 100 MW should be coordinated with the state-by-state caps that are recommended for no later than 2017.
    - The performance standards for units subject to the upcoming federal MACT requirements should be coordinated with the MACT requirements.
- In later phases (2020 to 2025), the performance standards should be coordinated with greenhouse gas reduction programs and other energy efficiency initiatives and be output-based.
- OTC's analysis (attached) shows that performance standards on larger fossil-fuel fired EGUs (based on a 30-day rolling average) are feasible and should be implemented on an aggressive timeframe (as early as 2017).
- EPA should consider including incentives (e.g., alternative compliance schedules not to exceed three years), to promote the repowering or replacement of existing units.
- After the adoption and implementation of performance standards, EPA should evaluate the feasibility of eliminating the state-by-state caps.

B. State-led Planning Process

The OTC States recommend that the state-led planning effort include all significantly contributing states (i.e., 1% of the NAAQS or greater impact) unless each state in the affected nonattainment area chooses to reduce the number of states involved.

- The OTC believes that this is the most appropriate way to identify those states that are required to participate in the state-led planning process as model performance (related to long-range transport) varies from one nonattainment area to another and the meteorology that affects some nonattainment areas is very complex.
- The states in the nonattainment area would use monitoring data, modeling and other information on ozone transport, meteorology, emissions, control programs, geography and chemistry to decide which significantly contributing states, if any, should be excused from the state-led planning process.
- Two scenarios are outlined below:
    - If the states in a nonattainment area have technical data that show that the state-led planning process for that area should be limited to just three or four states, that would be appropriate.
    - If the states in a nonattainment area are subject to highly complex transport patterns, it is most likely necessary to include all significantly contributing states in the state-led planning process.
- The OTC believes that the most appropriate way to address transport is through a suite of aggressive national programs to reduce NOx, VOC and SO_2 emissions from EGUs, other stationary sources, area sources and off-road and on-road mobile sources and that the role of the state-led planning process should be secondary.
- The OTC continues to have serious concerns over model performance related to long-range, aloft transport. It is critical for EPA to establish and implement performance criteria related to aloft transport to ensure that the process for identifying significantly contributing states is credible.
- As indicated in the September 2, 2009 joint letter, additional controls may be required where needed.

C. Eliminating Significant Contribution

The OTC States recommend that under the state-led attainment planning process, both the upwind states and EPA remain accountable to address contributions to downwind areas' nonattainment of both the ozone and $PM_{2.5}$ NAAQS by the relevant attainment dates, without designing any new "off-ramp" that avoids direct and timely action to reduce emissions that are in violation of CAA Section 110(a)(2)(D).

In addition to a program of controls for EGUs, OTC also urges EPA to address interstate transport through the development and implementation of national rules in

2012 or as early as feasible for additional controls on non-EGU sources, as supported in prior statements of the OTC to EPA. (*See*, *e.g.,* Statement on the Need for National Rulemaking and Implementation of Ozone Control Measures, November 14, 2007).

In acting on these recommendations, EPA can use the CAIR replacement rule to provide regulatory certainty to the EGU sector, which will enable business decisions that will move us many steps toward improved air quality and a more efficient electricity generating sector. We look forward to talking with you further about our recommendations for the CAIR replacement rule, and working with your staff as you expeditiously develop this important air quality and public health program.

Sincerely,

Amey Marrella
Connecticut

District of Columbia

Maine

Maryland

Massachusetts

Thomas S Burack
New Hampshire

Mark N Mauriello
New Jersey

New York

John Hanger
Pennsylvania

Rhode Island

Vermont

Enclosures

OTC CAIR Replacement Rule Recommendation Technical Support Document

The OTC is providing technical information in support of the recommendations to EPA on a CAIR replacement rule included in the September 2, 2009 joint letter from OTC and LADCO and the additional recommendations in the September 10, 2009 letter from OTC. The supporting materials provided below are organized as follows:

- Assessments and Rationale for Electricity Generating Units (EGUs)
  - EGU Emission Rates
  - Timing
  - Cost of Controls
  - Air Quality Benefits

- Assessments and Rationale for Other Sectors
  - Other Stationary Source Measures
  - Mobile Source Measures

- Appendix I – EGU Rates
- Appendix II – Timing
- Appendix III – Cost of Controls
- Appendix IV – Air Quality Benefits
- Appendix V – Other Sectors

The technical information included in this support document is based on studies and analyses conducted recently by the OTC, and where noted, by LADCO.

Assessments and Rationale for Electricity Generating Units (EGUs)

In its earliest response to EPA's proposed transport rule - first the Interstate Air Quality Rule (IAQR), and later, the Clean Air Interstate Rule (CAIR) - OTC provided comments and analyses showing that additional NOx and SO_2 reductions beyond those the rule provided would be needed for areas in the OTR to come into attainment with the ozone and $PM_{2.5}$ National Ambient Air Quality Standards (NAAQS). In response to the IAQR and CAIR, the OTC states developed a multi-pollutant position in 2004, using several different analyses of potential EGU control rates as a basis for developing national caps for NOx and SO_2 that were more stringent and earlier than those provided in CAIR.

The analysis used in OTC's recent review of the 2004 multi-pollutant position, along with evaluations of the current state of controls on EGUs and rate information extracted from recent American Electric Power Service Corp. (AEP) settlements and consent decrees was provided to the state collaborative process. Additional support for the timeframes and flexibility provisions in the OTC additional recommendations are provided in a short case study on the experiences of the Maryland Department of Environment (MDE) with its Healthy Air Act (HAA), as well as experiences in other states with their own state rules and additional information contained in the AEP settlements/consent decrees. Recent evaluations of control cost data that OTC has conducted for potential control strategies, including analyses for industrial, commercial and institutional boilers and boilers serving EGUs, provide data for relative cost/ton comparison between EGU and other sector NOx and SO_2 controls. An additional sensitivity analysis using OTC's latest SIP modeling runs, in tandem with the results from the State

Collaborative modeling runs, demonstrate the need for the air quality benefits that can be achieved from the rates and structure of the OTC recommendations.

EGU Emission Rates

In developing its 2004 position, OTC relied heavily on an analysis conducted by the National Association of Clean Air Agencies (NACAA) to support of its 2002 Principles for a Multi-Pollutant Strategy for Power Plants. The NACAA analysis demonstrated that reductions in the range of 82-88% by 2013 for SO_2 and 73-81% for NOx from a 2001 baseline were technologically feasible. Reductions within this range would yield emission rates as follows:

- NOx: 0.07 for new source BACT; 0.10 for retrofit BACT; and
- SO_2: 0.10 for new source BACT; 0.15 for retrofit BACT.

In comparison, the average emission rates for 2001 as reported by EPA were 0.37 lb/mmBtu for NOx and 0.84 lb/mmBtu for SO_2 (the 2001 baseline would not have included the NOx SIP Call).

OTC continued to work on and refine its position on EGU rates, based on additional analyses. In a 2007 review, the OTC Multi-P Workgroup performed an analysis to determine revised NOx and SO_2 cap levels.

Assessment 1. In the 2007 review of the OTC multi-pollutant position for EGUs, the OTC Multi-P Workgroup performed an analysis using the EPA Acid Rain database and information from the Department of Energy's Energy Information Agency (EIA) to examine reasonably cost-effective post-combustion EGU control technologies and determine fleet-wide average NOx and SO_2 emission rates for the fossil fuel-fired EGUs in the lower 48 states. The OTC Multi-P Workgroup concluded that for NOx, a 0.08 lbs/mmBtu fleet wide average emission rate would be achievable by 2018, along with an interim hard cap in 2012 based on a 0.125 lbs/mmBtu fleet-wide average. For SO_2 the OTC Multi-P Workgroup concluded that a 0.15 lb/mmBtu fleet wide average emission rate was achievable by 2018, along with an interim hard cap in 2012 based on a 0.25 lb/mmBtu fleet-wide average. The methodology applied by the OTC Multi-P Workgroup included the assumptions in Table I-1 below (also shown in Appendix I):

Table I-1. Control Assumptions for the Methodology Applied by the OTC Multi-P Workgroup

	EGU Size				Emission reduction assumed	
	25MW-<100MW	100MW-<200MW <50% input capacity	100MW-<200MW >50% input capacity	200MW or greater	For EGUs with existing "assumed" add-on controls	For EGUs applying "new" add-on controls
NOx	SNCR	SNCR	SCR	SCR	Remains same as 2008 controlled level	90% SCR 355 SNCR 55% SNCR to SCR increment
SO2	DSI	DSI	FGD	FGD	Remains same as 2008 controlled level	95% FGD 60% DSI

Control Technologies: DSI (Duct Sorbent Injection); FGD (Flue Gas Desulfurization); SCR (Selective Catalytic Reduction); SNCR (Selective Non-Catalytic Reduction)
* For EGUs identified as already incorporating the technology applied in the OTC Multi-P Workgroup's methodology their NOx emission rates were assumed to remain the same as their 2008 Ozone Season controlled

emission rates and their SO_2 emission rates were assumed to remain the same as their annual 2008 controlled emission rates.
**For each NOx and SO_2 control technology a 0.06 lb/MMBTU "basement" level (i.e., maximum control level) was assumed.

When these assumptions are applied to coal units (all coal and coal>100 MW) on a statewide average ozone season basis in the Ozone Transport Region (OTR), the result is a range of rates for NOx between 0.06 and 0.23 lb/mmBtu. A similar application in the LADCO states on a statewide average ozone season basis yields NOx rates in the range of 0.06 and 0.14 lb/mmBtu. Similarly, when the SO_2 assumptions are applied in the OTR on a statewide annual basis, the result is a range of rates for SO_2 between 0.06 and 0.32 lb/mmBtu. Following suit in the LADCO states on a statewide annual basis yields SO_2 rates in the range of 0.06 and 0.31 lb/mmBtu. Statewide rates for each state based on this analysis are outlined in Tables I-2 through I-5 in Appendix I.

This analysis does not include emissions from units in the states that use other fuels, such as natural gas, that would lower the overall statewide average emission rate. It also shows that some states with higher percentages of coal in their overall fuel mix will need flexibility in the regulatory structure and timing to achieve those rates.

Assessment 2. In a second assessment of potential EGU rates, OTC compiled information for each of the states in the eastern U.S. to show the average NOx and SO_2 emission rates from EPA's 2008 Clean Air Market Division (CAMD) database, based on units 25 MW and above for all fuels. Then the incremental NOx and SO_2 rates within the ranges discussed by the State Collaborative were calculated for each state, from 0.07 - 0.125 lb/mmBtu for NOx and from 0.15 - 0.30 lb/mmBtu for SO_2. The tons reduced at each control level increment and the percent reduction from 2008 levels is calculated for each state. The results are shown in Tables I-6 and I-7 in Appendix I, along with Tables I-8 and I-9 showing LADCO's data on achievable average annual emission rates based on their plant-level, unit-level analysis of coal fired units greater than 100 MW, and the timing of projected post-combustion controls installations. Comparing the OTC tables based on the CAMD data with the LADCO table, the 2008 rates are very close, despite the fact that the CAMD data includes all fuels and the LADCO data is for coal units only.

Assessment 3. Using a third data set to assess potential EGU emission rates, the OTC examined the recent consent decree signed by American Electric Service Corp. (AEP) which requires the installation of SCR and FGD controls on EGUs in a number of states including Indiana, Kentucky, Ohio, Virginia and West Virginia. The consent decree requires several of these units to meet a federally-enforceable 30-day rolling average emission rate of 0.100 lb/mmBtu for NOx and a 30-day rolling average emission rate of 0.100 lb/mmBtu for SO_2. Furthermore, repowering requirements as stipulated in the consent decree state that the technology achieve "equivalent environmental performance that at a minimum achieves and maintains a 30-day rolling average emission rate of 0.100lb/mmBtu or a 30-day rolling average removal efficiency of at least 95% for SO_2 and a 30-day rolling average emission rate of 0.070 lb/mmBtu for NOx.

The limits specified in the AEP consent decree provide additional support for the technical feasibility and cost effectiveness of the NOx and SO_2 emission rates "observed by" the State Collaborative EGU Technical Workgroup presented at the State Collaborative meetings held on October 7, 2008 and April 27-28, 2009. AEP would not have signed this consent decree if it was not certain that it could comply with all of its terms. Note that the NOx and SO_2 emission rates in the consent decree are more stringent than the NOx and SO_2 emission rates in the OTC recommendations because they are based on unit specific, 30-day rolling average emission rates rather than statewide average emission rates. If EGU retrofits can achieve the NOx and SO_2 rates specified in the AEP consent decree on a unit specific basis, then it should be feasible for other EGUs to achieve these emission rates on a statewide average basis.

Timing

Timing flexibility is a key issue in developing an EGU control strategy. If the regulatory structure is designed correctly, it will provide incentives to get controls installed quickly. One example of this is provided by the Maryland Department of Environment's (MDE) experience with their Healthy Air Act (HAA), which was passed in 2006, with final rules issued in January 2007 (see MDE case study in Appendix II). MDE's experience with the HAA demonstrates that it is possible to achieve simultaneous, rather than sequential, installation of controls in less than 3 years after promulgation of the rules requiring those controls.

- In Maryland, 3 SCRs and 6 SNCRs on coal units ranging in size from 125 - 600 MW, and 6 FGD on 9 coal-fired units ranging in size from 200 -700 MW are installed or will have completed installation by the end of 2009, or less than 3 years after the HAA rules were promulgated. Four SCRs had been installed on coal-fired power plants in Maryland prior to the HAA.
- MDE included a waiver for units that could not meet the control levels by the date required, providing additional time for them to install controls. The waiver was not utilized by any EGU.
- The installations responding to the HAA rules occurred at the same time that controls were being required for CAIR and a number of consent decrees on EGUs. Despite these competing interests, there were no delays in construction or installation due to labor or equipment constraints.

More specific information can be found in Appendix II, Example 1 on the MDE HAA case study, including a schematic of the timeline of installations on specific EGUs in response to the rule.

In another example from Delaware, the state established phased NOx and SO_2 limits in Regulation 1146, promulgated in December 2006, with the first phase of controls required to be operational in May 2009. This provided a 2.5-year window from promulgation of the rule to installation and operation of controls for the first phase of NOx and SO_2 controls. The emission rates and timing for the reductions required by Delaware's Regulation 1146 is applicable to coal-fired and residual oil-fired units 25 MW and above are as follows:

- NOx = 0.15 lb/mmBtu on all units beginning May 1, 2009 through December 2011, with a second, more stringent limit on the same units of 0.125 lb/mmBtu for the period January 1, 2012 and beyond (limits are on a rolling 24-hour basis);
- SO_2 = 0.37 lb/mmBtu on all units beginning May 1, 2009 through December 2011, with a second, more stringent limit on coal-fired units of 0.26 lb/mmBtu for the period January 1, 2012 and beyond (limits are on a rolling 24-hour basis); and
- Residual oil-fired units may not accept residual fuel oil for combustion that has a sulfur content in excess of 0.5% by weight from January 1, 2009 and beyond.

More information on Delaware's Regulation 1146 can be found at:
http://regulations.delaware.gov/AdminCode/title7/1000/1100/1146.shtml

Finally, data collected on controls resulting from EPA's NOx SIP Call show that a over 75 percent of the SCR units installed occurred within a 4-year window, between 2003 to 2007, with more than 50 percent of the installations occurring in the 2003-2004 timeframe. More information on the installation of SCR controls in response to EPA's NOx SIP Call can be found in Appendix II, Example 2.

Cost of Controls

EPA needs to perform a comprehensive cost analysis for the CAIR replacement rule; however, in the interim the data show that aggressive controls on EGUs continues to be the most cost-effective option available to the states in meeting the ozone and PM $_{2.5}$ standards.

Table III-1 in Appendix III provides recently developed cost estimates for various NOx and SO_2 controls in 2008 dollars, including selective non-catalytic reduction (SCR), selective catalytic reduction (SCR), flue gas desulfurization, low NOx burners (LNB)and combinations of these controls on coal-fired, residual oil-fired, distillate oil-fired and natural gas-fired boilers. The data shows that the cost for controls caps out at $4,900 per ton of NOx removed for an SCR and $3,600 per ton of SO_2 removed for a dry FGD system (dry scrubber) installed on a 250 mmBtu/hr (approximately 73 MW) coal-fired boiler operating at 66 percent capacity. The NOx control costs for 250 mmBtu/hr fossil fuel-fired boilers serving EGUs range from $1,100 to $8,700 per ton of NOx removed and the SO_2 control costs for 250 mmBtu/hr coal-fired boilers serving EGUs range from $1,400 to $3,600 per ton of SO_2 removed.

OTC is conducting an extensive examination of potential control measures to consider as additional strategies in their ozone and PM $_{2.5}$ SIPs. The costs of several of these controls on a $/ton basis far exceed the cost of EGU controls, as shown in Tables III-2 and III-3 in Appendix III.

Air Quality Benefits

The State Collaborative effort has produced modeling analyses to examine the impact that a CAIR replacement rule might have on air quality in the Eastern United States. These regional modeling results show that an EGU based strategy would have a positive impact on $PM_{2.5}$ and ozone air quality in the region and that while nearby sources have by far the greatest impact, significant contribution to levels of ozone and $PM_{2.5}$ can come from states several hundred miles away. This effort also shows that with an EGU strategy that approximates CAIR and other currently adopted measures many areas are still above the current ozone (0.075 ppm) and $PM_{2.5}$ NAAQS.

Furthermore, the State Collaborative modeling also show that even with the most stringent NOx (0.07 lb/mmBtu) and SO_2 (0.10 lb/mmBtu) emission control rates applied on a unit-by-unit basis, a number of areas remain in non-attainment . Under these emission limits the modeling shows 23 counties in non-attainment for the 75 ppb ozone standard, 10 counties not meeting the $PM_{2.5}$ daily standard, and 3 counties in non-attainment for the PM $_{2.5}$ annual standard. The State Collaborative modeling is not "SIP quality," so it was conducted to provide, at best, ballpark estimates that are only meant to be directionally correct. Even with the substantial improvement in air quality shown in the 2018 modeling results, however, approximately 37 million people will still be exposed to unhealthy levels of air pollution. Results from the State Collaborative air quality modeling are summarized in the charts and maps on pages 1-2 of Appendix IV.

To ascertain the level of reductions that might be necessary to meet the current ozone NAAQS, the OTC performed sensitivity modeling. This sensitivity modeling employed across-the-board reduction in NOx emissions (point, area and mobile sources). This sensitivity modeling indicates that by reducing NOx emissions by 40 % from all sectors attainment with the current ozone NAAQS is possible. While it is likely impossible to reduce NOx emissions by 40 % from all sectors, this provides a pathway to determine the level of emissions reductions needed for planning purposes. The ultimate decision on the measures chosen will be based on feasibility (both technical and cost) and effectiveness. Results from the OTC sensitivity modeling are summarized in the maps and charts on pages 3-5 of Appendix IV.

Assessments and Rationale for Other Sectors

The states in the eastern U.S. have affirmed that emission reductions beyond what is achievable from EGU sources alone will be necessary to comply with the ozone and $PM_{2.5}$ standards, and to address transport and regional haze. Both the joint OTC-LADCO recommendation of September 2, 2009 and the additional recommendations provided by OTC in the September 20, 2009 letter put forward potential EGU emission rates for consideration by EPA that go beyond the original CAIR levels. It is important that significant reductions are also obtained from sources in the area and mobile source sectors to bring areas into attainment with air quality standards and mitigate transport of air pollutants and their precursors from one part of the country into another.

Other Stationary and Area Source Measures

The OTC states have taken actions beyond the EGU sector during the past 10 years to reduce NOx and VOC emissions from non-EGU stationary and area sources including consumer products, architectural and industrial maintenance coatings, adhesives and sealants, solvents, portable fuel containers, asphalt paving, distributed generators, cement kilns, glass furnaces and industrial, commercial and institutional (ICI) boilers. The model rules developed in 2001 and 2006 for these source categories have been developed and implemented by many of the OTC states as outlined in Tables V-1 through V-4 in Appendix V.

The OTC has long advocated to EPA that these rules be applied nationally, and EPA has taken national action in some areas, e.g., consumer products. The ICI boiler model rule was used in last year's State Collaborative discussions with LADCO to help develop a joint set of recommendations for a national ICI boiler strategy to EPA. Further, in the current planning work occurring in the OTR for the new ozone and $PM_{2.5}$ SIPs, the OTC is continuing to drill down into other non-EGU stationary and area source categories to find additional reductions, as outlined in the potential measures illustrated in Tables III-2 and III-3 in Appendix III.

Mobile Source Control Measures

The OTC states have also implemented numerous programs to reduce ozone precursor emissions from mobile sources. The majority of the states have adopted California Low Emission Vehicle standards applicable to new vehicles, which are more stringent than federal standards. To address emissions from in-use vehicles, the states have implemented Inspection and Maintenance Programs and aggressive diesel retrofit programs.

States have also exercised their option to opt-in to federal reformulated gasoline as part of their State Implementation Plans (SIPs). To counter growth in vehicle miles traveled, states in the region have included transportation control measure in their SIPs (e.g., improved public transit) and have implemented many air quality improvement projects through the conformity review process to ensure mobile source emission budgets are met.

The OTC Mobile Source Committee is currently working on additional mobile measures as part of the 2008 ozone standard regional attainment planning process. It is supporting the adoption of national measures in areas where the states are pre-empted from taking action. For example, it has submitted a letter of support for the ocean going vessels Emission Control Areas (ECA) designation to reduce emissions from port areas. And it has encouraged EPA to issue guidance from EPA on its Aftermarket Catalyst Replacement Standards policy. The OTC is also advocating for EPA to address backsliding with regard to the Renewable Fuel Standard (RFS), to ensure that phase 2 of the program does not further exacerbate criteria pollutant impacts that have occurred in Phase 1 of the program.

Other mobile measures that are under review in the OTC and NESCAUM states are:

- Offshore lightering for ships (VOC reductions)
- Seaports strategy (PM strategy primarily)
- Adoption and enforcement of non-road idling requirements (VOC, NOx and GHG reductions)
- Regional fuel for OTC states/areas that have not yet adopted RFG (i.e. large parts of PA and NY))
- Heavy duty diesel strategies such as Inspection and Maintenance Programs for Diesels and expansion of diesel retrofit programs
- Additional VMT-reduction strategies that will result in ozone precursor and GHG reductions

In the context of Greenhouse Gas Emissions, the OTC states have been involved in numerous actions that will result in the overall reduction of ozone precursors as well as GHG emissions. The litigation of Mass v. EPA, joined by many OTC states, and the active support of OTC-member states for the integration of motor vehicle efficiency standards and GHG emission standards into a new federal policy endorsed by President Obama are examples. The RGGI States, with PA, are also working on the development of a low carbon fuel standard (LCFS), including the potential to improve the infrastructure for electric vehicles that may be part of that strategy, and smart growth/VMT and land use measures to reduce mobile emissions.

Appendix I – EGU Rates

Assessment 1

The methodology applied by the OTC Multi-P Workgroup and used for this assessment is included the assumptions in Table 1-1 below:

Table I-1. Control Assumptions for the Methodology Applied by the OTC Multi-P Workgroup

	EGU Size				Emission reduction assumed	
	25MW-<100MW	100MW-<200MW <50% input capacity	100MW-<200MW >50% input capacity	200MW or greater	For EGUs with existing "assumed" add-on controls	For EGUs applying "new" add-on controls
NOx	SNCR	SNCR	SCR	SCR	Remains same as 2008 controlled level	90% SCR 355 SNCR 55% SNCR to SCR increment
SO2	DSI	DSI	FGD	FGD	Remains same as 2008 controlled level	95% FGD 60% DSI

Control Technologies: DSI (Duct Sorbent Injection); FGD (Flue Gas Desulfurization); SCR (Selective Catalytic Reduction); SNCR (Selective Non-Catalytic Reduction)

* For EGUs identified as already incorporating the technology applied in the OTC Multi-P Workgroup's methodology their NOx emission rates were assumed to remain the same as their 2008 Ozone Season controlled emission rates and their SO_2 emission rates were assumed to remain the same as their annual 2008 controlled emission rates.

**For each NOx and SO_2 control technology a 0.06 lb/MMBTU "basement" level (i.e., maximum control level) was assumed.

Based on the above assumptions, the "predicted" statewide average ozone season NOx emission rates are shown below:

Table I-2. All Coal

State	Predicted NOx Mass	2008 O.S. Heat Input	Predicted Avg NOx Rate	State	Predicted NOx Mass	2008 O.S. Heat Input	Predicted Avg NOx Rate
CT	395	13,163,750	0.0600	IL	13,297	443,240,475	0.0600
DE	1,863	20,145,049	0.1850	IN	12,814	427,135,645	0.0600
MA	1,569	40,324,189	0.0778	MI	12,645	208,348,933	0.1214
MD	5,345	112,279,215	0.0952	OH	19,156	274,909,447	0.1394
NH	1,754	15,347,558	0.2286	WI	34,845	627,665,733	0.1110
NJ	2,438	30,586,717	0.1594				
NY	4,321	76,120,595	0.1135				
PA	25,880	446,215,793	0.1160				
VA	6,070	119,264,709	0.1018				

If only coal-fired units with a nameplate rating of 100MW or greater are to be considered, the "predicted" statewide average ozone season NOx emission rates are shown below:

Table I-3. >100 MW Coal

State	Predicted NOx Mass	2008 O.S. Heat Input	Predicted Avg NOx Rate	State	Predicted NOx Mass	2008 O.S. Heat Input	Predicted Avg NOx Rate
CT	395	13,163,750	0.0600	IL	12,817	417,656,155	0.0614
DE	1,863	20,145,049	0.1850	IN	23,368	492,447,671	0.0949
MA	1,298	35,899,623	0.0723	MI	13,082	278,933,070	0.0938
MD	5,127	110,241,907	0.0930	OH	26,348	519,802,282	0.1014
NH	1,362	11,735,819	0.2321	WI	7,293	185,704,212	0.0785
NJ	2,284	29,350,532	0.1556				
NY	3,828	68,614,070	0.1116				
PA	24,430	430,902,559	0.1134				
VA	4,918	107,929,830	0.0911				

Based on the above assumptions, the "predicted" statewide average annual SO2 emission rates for all coal-fired EGUs are shown below:

Table I-4. All Coal

State	SO_2 Mass	Heat Input	SO_2 Rate	State	SO_2 Mass	Heat Input	SO_2 Rate
CT	915	30,494,774	0.0600	IL	52,260	1,032,913,414	0.1012
DE	6,877	53,729,573	0.2560	IN	184,979	1,183,751,273	0.3125
MA	15,976	101,700,315	0.3142	MI	30,911	714,421,520	0.0865
MD	12,891	255,974,177	0.1007	OH	149,190	1,291,957,283	0.2310
NH	3,560	38,335,281	0.1857	WI	21,100	453,687,252	0.0930
NJ	4,226	62,812,030	0.1346				
NY	20,848	181,042,512	0.2303				
PA	133,087	1,068,514,484	0.2491				
VA	18,790	279,184,954	0.1346				

If only coal-fired units with a nameplate rating of 100MW or greater are to be considered, the "predicted" statewide average annual SO2 emission rates are shown below:

Table I-5. >100 MW Coal

State	SO_2 Mass	Heat Input	SO_2 Rate	State	SO_2 Mass	Heat Input	SO_2 Rate
CT	915	30,494,774	0.0600	IL	42,489	991,323,073	0.0857
DE	6,877	53,729,573	0.2560	IN	159,449	1,149,099,381	0.2775
MA	14,861	93,738,547	0.3171	MI	21,018	653,861,186	0.0643
MD	11,412	250,831,639	0.0910	OH	130,335	1,241,187,821	0.2100
NH	1,565	30,332,534	0.1032	WI	15,199	432,619,948	0.0703
NJ	3,582	59,793,990	0.1198				
NY	15,695	160,893,978	0.1951				
PA	119,772	1,034,993,798	0.2314				
VA	15,312	250,443,277	0.1223				

Assessment 2

Table I-6. NOx Table

State	NOx Tons	NOx Rate	0.125	Red. 0.125	% Red. 0.125	0.1	Red. 0.10	% Red. 0.10	0.07	Red. 0.07	% Red. 0.07	Heat Input
IL	119967	0.226	66295	53672	45	53036	66931	56	37125	82842	69	1060713465
IN	196135	0.306	80199	115935	59	64159	131975	67	44912	151223	77	1283188639
MI	103474	0.275	46998	56476	55	37598	65875	64	26319	77155	75	751966181
OH	235126	0.355	82817	152309	65	66254	168872	72	46378	188749	80	1325072026
WI	47343	0.190	31099	16244	34	24879	22464	47	17415	29927	63	497577808
LADCO TOTAL	702043	0.285	307407	394636	56	245926	456117	65	172148	529895	75	4918518119
PA	175218	0.286	76626	98592	56	61301	113917	65	42911	132308	76	1226016925
NY	30871	0.109	30871	0	0	28384	2487	8	19869	11002	36	567686169
NJ	9143	0.096	9143	0	0	9143	0	0	6659	2483	27	190267033
MD	35922	0.263	17048	18875	53	13638	22284	62	9547	26376	73	272761427
VA	43017	0.237	22652	20365	47	18122	24895	58	12685	30332	71	362431406
MA	9353	0.068	9353	0	0	9353	0	0	9353	0	0	274620434
NH	4641	0.096	4641	0	0	4641	0	0	3373	1268	27	96364833
CT	3116	0.067	3116	0	0	3116	0	0	3116	0	0	92717786
DE	8936	0.279	4003	4934	55	3202	5734	64	2241	6695	75	64042015
ME	680	0.022	680	0	0	680	0	0	680	0	0	61863689
DC	94	0.280	42	52	55	33	60	64	23	70	75	668330
RI	462	0.017	462	0	0	462	0	0	462	0	0	55392442
VT	296	0.140	263	32	11	211	85	29	147	148	50	4214041
OTC TOTAL	321749	0.197	204315	117434	36	163452	158297	49	114417	207333	64	3269046530
AL	112614	0.240	58697	53917	48	46958	65656	58	32870	79744	71	939155771
FL	155451	0.197	98770	56681	36	79016	76435	49	55311	100140	64	1580319063
GA	105894	0.221	59900	45994	43	47920	57974	55	33544	72350	68	958401269
KY	157847	0.319	61918	95929	61	49535	108312	69	34674	123173	78	990691497
MS	41917	0.237	22110	19807	47	17688	24229	58	12381	29535	70	353752142
NC	54652	0.144	47283	7369	13	37826	16826	31	26478	28174	52	756524591
SC	42045	0.190	27615	14430	34	22092	19953	47	15465	26581	63	441843531
TN	85543	0.294	36392	49151	57	29114	56430	66	20380	65164	76	582275154
WV	97331	0.228	53329	44002	45	42663	54668	56	29864	67467	69	853266499
Other State Total	853294	0.229	466014	387280	45	372811	480483	56	260968	592326	69	7456229518
TOTAL	1877087	0.240	977737	899350	48	782190	1094897	58	547533	1329554	71	15643794167

Table I-7. SO2 Table

State	SO2 tons	SO2 Rate	0.3	Red. 0.3	% Red.0.3	0.23	Red. 0.23	% Red. 0.23	0.2	Red. 0.20	% Red. 0.20	0.15	Red. 0.15	% Red. 0.15	Heat Input
IL	257431	0.485	159107	98324	38	121982	135449	53	106071	151360	59	79554	177877	69	1060713465
IN	593154	0.925	192478	400676	68	147567	445587	75	128319	464835	78	96239	496915	84	1283188639
MI	326501	0.868	112795	213706	65	86476	240024	74	75197	251304	77	56397	270103	83	751966181
OH	709995	1.072	198761	511234	72	152383	557611	79	132507	577487	81	99380	610614	86	1325072026
WI	129695	0.521	74637	55058	42	57221	72473	56	49758	79937	62	37318	92376	71	497577808
LADCO TOTAL	2016775	0.820	737778	1278997	63	565630	1451145	72	491852	1524923	76	368889	1647886	82	4918518119
PA	831915	1.357	183903	648012	78	140992	690923	83	122602	709313	85	91951	739964	89	1226016925
NY	65427	0.231	65427	0	0	65284	143	0	56769	8658	13	42576	22850	35	567686169
NJ	21204	0.223	21204	0	0	21204	0	0	19027	2177	10	14270	6934	33	190267033
MD	227198	1.666	40914	186283	82	31368	195830	86	27276	199921	88	20457	206740	91	272761427
VA	125985	0.695	54365	71620	57	41680	84306	67	36243	89742	71	27182	98803	78	362431406
MA	46347	0.338	41193	5154	11	31581	14766	32	27462	18885	41	20597	25751	56	274620434
NH	36895	0.766	14455	22440	61	11082	25813	70	9636	27259	74	7227	29668	80	96364833
CT	3955	0.085	3955	0	0	3955	0	0	3955	0	0	3955	0	0	92717786
DE	31808	0.993	9606	22202	70	7365	24444	77	6404	25404	80	4803	27005	85	64042015
ME	1041	0.034	1041	0	0	1041	0	0	1041	0	0	1041	0	0	61863689
DC	212	0.634	100	111	53	77	135	64	67	145	68	50	162	76	668330
RI	18	0.001	18	0	0	18	0	0	18	0	0	18	0	0	55392442
VT	2	0.001	2	0	0	2	0	0	2	0	0	2	0	0	4214041
OTC TOTAL	1392007	0.852	436183	955825	69	355648	1036359	74	326905	1065102	77	245178	1146829	82	3269046530
AL	357547	0.761	140873	216673	61	108003	249544	70	93916	263631	74	70437	287110	80	939155771
FL	263745	0.334	237048	26697	10	181737	82008	31	158032	105713	40	118524	145221	55	1580319063
GA	514539	1.074	143760	370779	72	110216	404323	79	95840	418699	81	71880	442659	86	958401269
KY	344356	0.695	148604	195753	57	113930	230427	67	99069	245287	71	74302	270055	78	990691497
MS	65317	0.369	53063	12254	19	40681	24635	38	35375	29941	46	26531	38785	59	353752142
NC	227030	0.600	113479	113551	50	87000	140030	62	75652	151378	67	56739	170291	75	756524591
SC	157190	0.712	66277	90914	58	50812	106378	68	44184	113006	72	33138	124052	79	441843531
TN	208069	0.715	87341	120728	58	66962	141107	68	58228	149842	72	43671	164398	79	582275154
WV	301574	0.707	127990	173584	58	98126	203449	67	85327	216248	72	63995	237579	79	853266499
Other State Total	2439368	0.654	1118434	1320933	54	857466	1581901	65	745623	1693745	69	559217	1880150	77	7456229518
TOTAL	5848149	0.748	2292395	3555755	61	1778744	4069405	70	1564379	4283770	73	1173285	4674865	80	15643794167

LADCO Analysis

Based on this plant-level, unit-level analysis of coal-fired units, the LADCO States identified the following achievable annual average emission rates:

Table I-8. NOx and SO_2 Analysis

NOx					
Year	**Illinois**	**Indiana**	**Michigan**	**Ohio**	**Wisconsin**
2008	0.23	0.305	0.29	0.36	0.21
2013	0.11 – 0.12	0.297	0.18	0.24	0.13
2014	0.11 – 0.12	0.171	0.15	0.18	0.12
2015	0.11 – 0.12	0.165	0.13	0.17	0.10
2017	0.11 – 0.12	0.114	0.11	0.12	0.09
SO2					
Year					
2008	0.50	0.93	0.91	1.09	0.57
2013	0.24 – 0.44	0.67	0.58	0.75	0.39
2014	0.20 -0.43	0.66	0.45	0.65	0.39
2015	0.19 – 0.28	0.66	0.37	0.65	0.25
2017	0.15 – 0.23	0.25	0.25	0.256	0.16

It should be noted that the analysis is based on coal-fired units. Consideration of all units (coal, oil, gas, and biomass) will result in emission rates slightly below those indicated above.

The number of post-combustion controls assumed in this analysis is provided below. The total amount of mega-wattage controlled in each state is on the order of 80-90%.

Table I-9. Analysis of Post-combustion Controls by Year

	NOx																**SO2**				
	SCR					**SNCR**					**ALL**						**FGD**				
	IL	IN	MI	OH	WI	IL	IN	MI	OH	WI	IL	IN	MI	OH	WI		IL	IN	MI	OH	WI
2008		23	3	19	1		4	0	15	1	17	27	3	34	2		6	23	2	16	1
2013		23	7	25	5		7	0	11	8	32	30	7	36	13		20	29	7	25	6
2014		23	12	26	5		7	0	11	8	34	30	12	37	13		29	29	12	33	6
2015		23	17	27	5		17	0	11	15	36	40	17	38	20		35	29	17	33	6
2017		32	25	34	8		17	0	14	15	36	49	27	48	23		37	48	27	41	13

Note: IL and OH numbers reflect number of units controlled, and IN and WI numbers reflect number of installations (which may cover several units).

APPENDIX II – Timing

Example 1: Case Study

Maryland Healthy Air Act
Deadlines and the Installation of Control Equipment

BACKGROUND

In April of 2006, the Maryland General Assembly adopted the Maryland Healthy Air Act. The bill was signed into law on April 6, 2006. In general, the law required significant reductions in Nitrogen Oxides (NOx), Sulfur Dioxide (SO2) and Mercury (HG) from electricity generating units (EGUs) in Maryland. It also required Maryland to join the Regional Greenhouse Gas Initiatve (RGGI), the first cap-and-trade program to tackle CO2 in the Country.

Portions of Maryland are nonattainment for the federal Ozone and PM2.5 Standards. NOx reductions were a critical part of Maryland's plan to reduce ground level ozone. Reductions in SO2 and NOx are both important to the States plans to lower fine particle levels. Maryland also had multiple issues with mercury and the Chesapeake Bay.

The Healthy Air Act was driven by the concept that the emission reductions from the Healthy Air Act would be important to the States own efforts to solve its air quality problems. It did, however, recognize that Maryland had a responsibility under the Clean Air Act to reduce pollution to also help downwind neighbors.

The implementing regulations were put on a fast track and were adopted on January 18th, 2007.

The Healthy Air Act includes two phases of reductions: 2009 and 2012 for NOx and 2010 and 2012 for SO2 and mercury. Table 1 below summarizes the additional NOx and SO2 reductions required in 2009, 2010, 2012 and 2013.

Table 1
Maryland Healthy Air Act Emission Reductions

	2009	2010	2012	2013
NOx	70%		75%	
SO2		80%		85%
Mercury		80%		90%

Because of pre-2006 control programs like the OTC NOx Budget Rule, total NOx reductions from Maryland EGUs between 1990 and 2012 are estimated to be over 85%.

THE DEADLINES

While the Healthy Air Act was being debated, there was considerable concern raised over the issue of timing. In general, Maryland's two major power generators argued that the 2 years to install NOx controls and the 2 ½ to 3 years to install SO2 and Mercury controls were a huge and perhaps impossible challenge. Over 60% of Maryland's electricity comes from coal.

Maryland's largest generator (3 plants – 9 units) argued that the only feasible way to install the controls required by the Healthy Air Act was to go in series (plant-by-plant) and that a plant-by-plant approach could take over 6 years.

As a result of this debate, the law included several waiver provisions to allow affected sources more time, without penalty, if such delays could be justified. For Phase 1 (2009 for NOx and 2010 for SO2 and HG) there have been no requests for waivers. Both of Maryland's major generators have installed their controls in parallel, not in series (plant-by-plant).

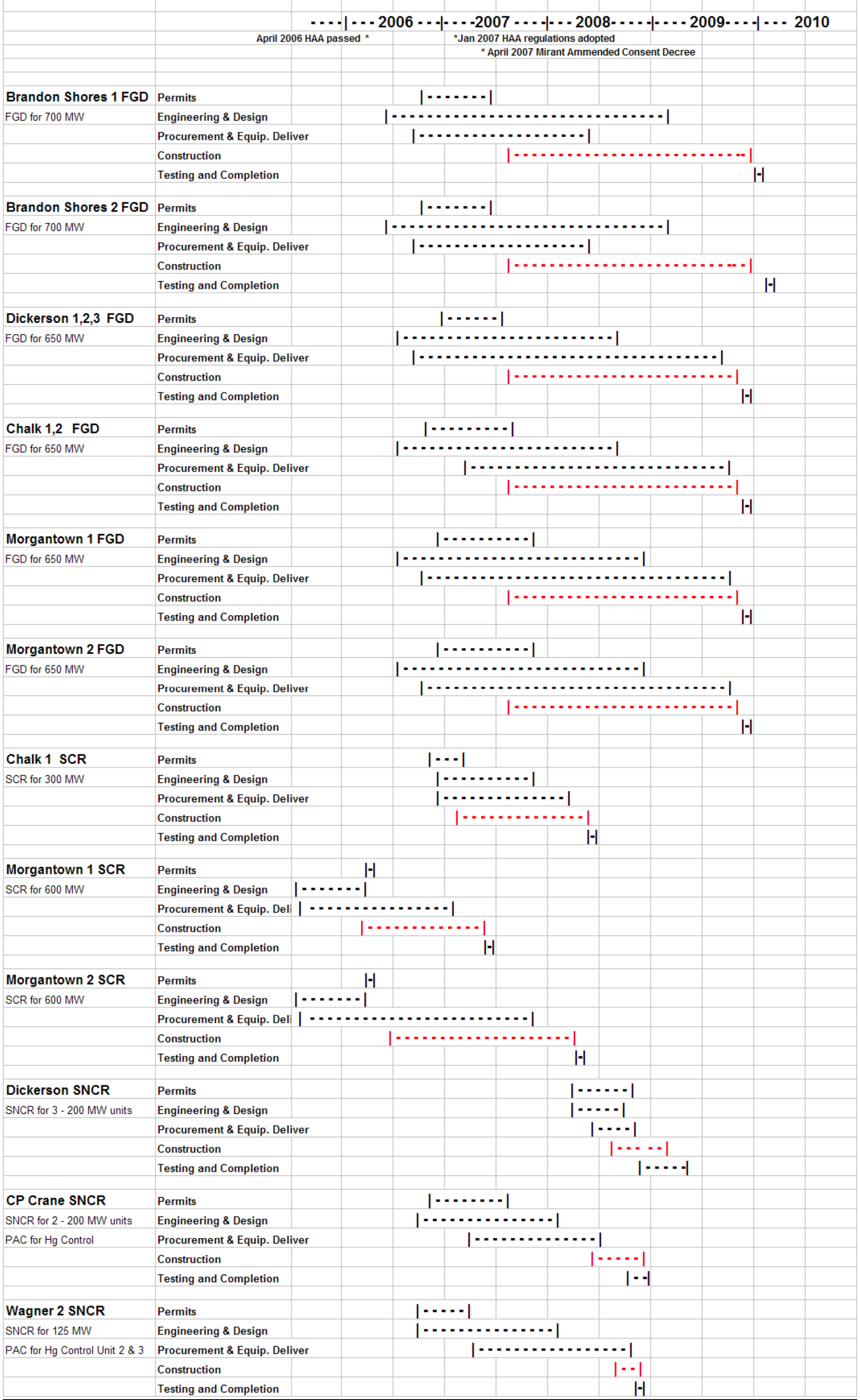
Because of the Healthy Air Act, by 2010, over $2 Billion will have been invested in new control equipment (6 scrubbers, 3 SCRs, 6 SNCRs). Four SCRs and numerous combustion modifications had been installed on coal fired power plants in the Maryland prior to the Healthy Air Act.

Table 2 below summarizes the planning and installation schedules for the six largest plants in the State.

Construction schedules for the FGD ran approximately 28 months each. Engineering economies were realized by using the same size FGD for the four Mirant installations. While the number of units served by each FGD in the three plants in the Mirant system varied, the total MW of capacity feeding each FGD was approximately the same at about 600 MW. This allowed the same engineering design to be used for each FGD. The two FGD at Brandon Shores are also identical to each other.

While the use of two FGD designs assisted with the timely completion of the six projects, material handling design and ductwork to and from the FGDs were different at each site. Three of the FGD projects had to deal with SCR construction occurring simultaneous to the FGD construction, and accommodations for crane availability had to be carefully scheduled. All of the FGD's required new stacks with fiber glass liners. The liners were constructed on site and the equipment installed to fabricate the liners the required permits to construct from MDE.

Table 2 Healthy Air Act Project Time Line in Maryland



OTHER MID-ATLANTIC STATES

Between 2006 and 2009 there were other very significant efforts taking place in the Mid-Atlantic area to add scrubbers, SCRs and SNCRs. Because of state programs and the Clean Air Interstate Rule (CAIR), Virginia, New Jersey, Delaware, West Virginia and North Carolina all had significant control technology installation efforts taking place between 2006 and 2009.

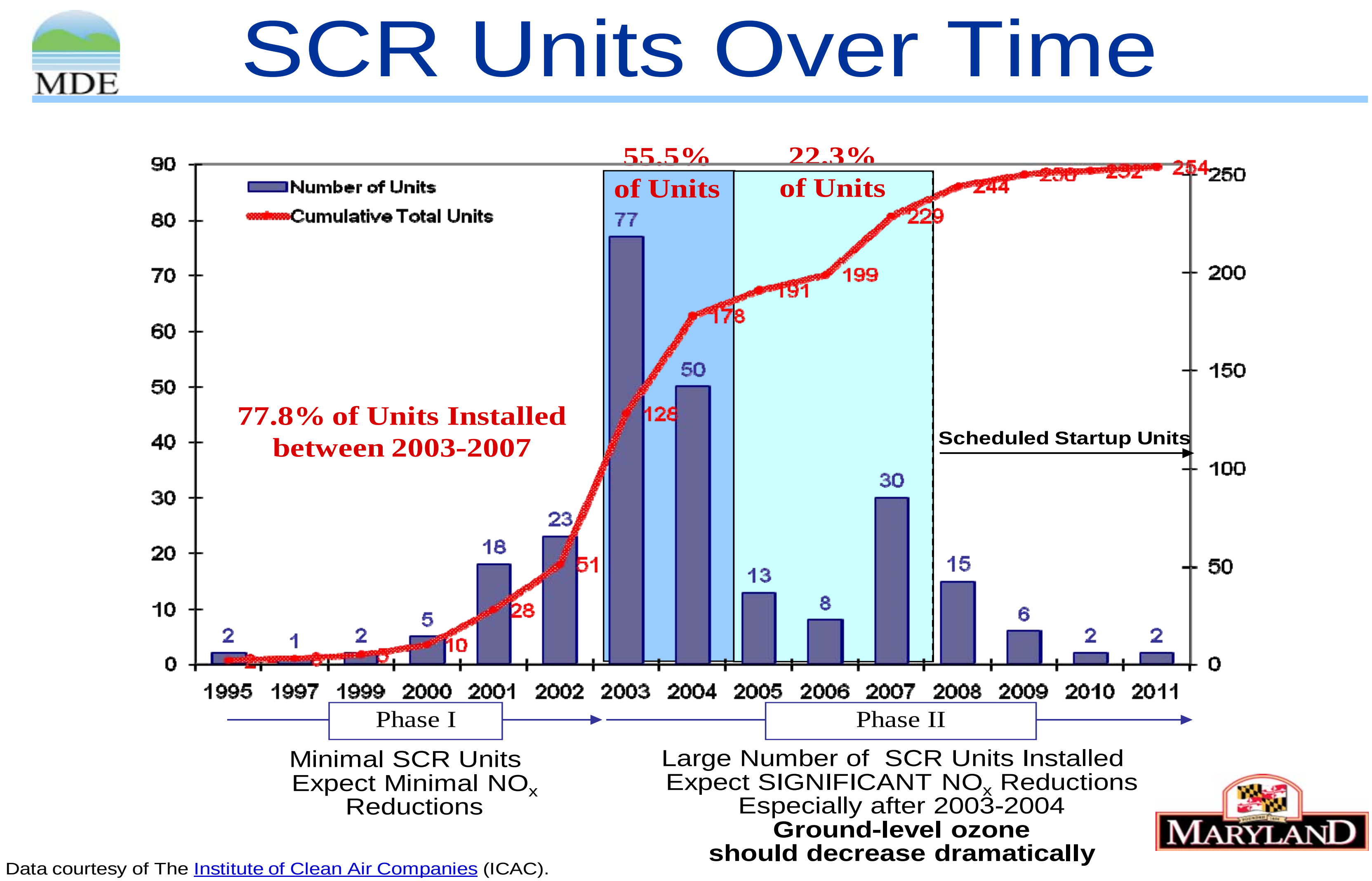
CONCLUSION

With the appropriate regulatory structure, very significant pollution control systems, including FGDs, SCRs and SNCRs, can be installed in multiple plants owned by the same company, in parallel, in a relatively short timeframe.

Supplemental Information:

- Law: http://mlis.state.md.us/2006rs/bills/sb/sb0154e.pdf
- Regulation: http://www.mde.state.md.us/assets/document/26-11-27_MD_Healthy_Air_Act.pdf

Example 2: Installation of SCR Units from EPA's NOx SIP Call



Appendix III – Cost of Controls

Table III-1. Available Emission Control Devices, Emission Reductions and Estimated Costs[1]

Fuel Type	Pollutant	Available Control Device	Expected Emission Reduction (%)	Control Cost Estimate[a] ($/ton removed)
Coal-Fired	NOx	Selective Non-Catalytic Reduction (SNCR) Selective Catalytic Reduction (SCR)	45% 85%	$2,500 - $3,000 $1,600 - $4,900
	SO_2	Flue Gas Desulfurization (FGD) system (dry scrubber) Wet FGD system (wet scrubber)	95% 95%	$1,500 - $3,600 $1,400 - $3,400
Residual Oil-Fired	NOx	Low NOx Burners (LNB) LNB plus Flue Gas Recirculation (FGR) Selective Non-Catalytic Reduction (SNCR) LNB plus SNCR Selective Catalytic Reduction (SCR)	50% 60% 50% 65% 85%	$1,100 - $4,400 $2,600 - $5,400 $3,100 - $4,000 $3,500 - $6,400 $2,600 - $8,300
Distillate Oil-Fired	NOx	Low NOx Burners (LNB)	50%	$2,200 - $8,700
Gas-Fired	NOx	Low NOx Burners (LNB)	50%	$2,200 - $8,700

Note: [a]Cost estimates shown are in 2008 dollars for a **250 MMBtu/hr boiler (≈ 73 MW)** operating at 66 percent capacity and operating 8,760 hours per year

[1] New Hampshire Department of Environmental Services (October 2008) Draft ICI Boiler NOx and SO_2 Control Cost Estimates [PowerPoint slides]. (Andy Bodnarik, 2009)

Table III-2 Stationary and Area Source Measures

NOx Measure	State Rules	National Measure	Emissions Reduction	Cost
Boilers serving EGUs	DE, NJ,MA, MD	*	413 TPD OTR	$1,100 - 8,700 per ton
New Small Gas Boilers	CA, TX	*	53 TPD OTR	$3,300 to $16,000 per ton
Municipal waste incinerators	NJ, MD	*	14 TPD OTR	$2,140 per ton (SNCR)
HEDD EGUs	NJ	*	TBD	$45,000 to $300,000 per unit
Stationary Generator Regulation (DG)	DE, MA, MD, NJ	*	TBD	$39,700 to $79,700 per TPD
Minor New Source Review	DE, CT, MD, MA, NJ, RI	*	TBD	$600 to $18,000 per ton
Energy security / Energy efficiency	TBD	*	TBD	TBD

Table III-3 Stationary and Area Source VOC Measures

VOC Measure	State Rules	National Measure	Emissions Reduction	Cost
AIM rule	CA	*	50 TPD OTR	$2,240 per ton
Auto Refinishing	CA	*	21 TPD OTR	$2,860 per ton
Consumer Products 2006	CA	*	19 TPD OTR	$7,700 per ton
Lower VOC Solvent Degreaser	MD, CA	*	13 TPD OTR	$1,400 per ton
Gas Stations	TBD	*	TBD	TBD
Large VOC Storage Tanks	MD, NJ	*	TBD	$2,288 to $29,000 per ton
Minor New Source Review	DE, CT, MD, MA, NJ, RI	*	TBD	TBD

Appendix IV – Air Quality Benefits

State Collaborative Modeling Results

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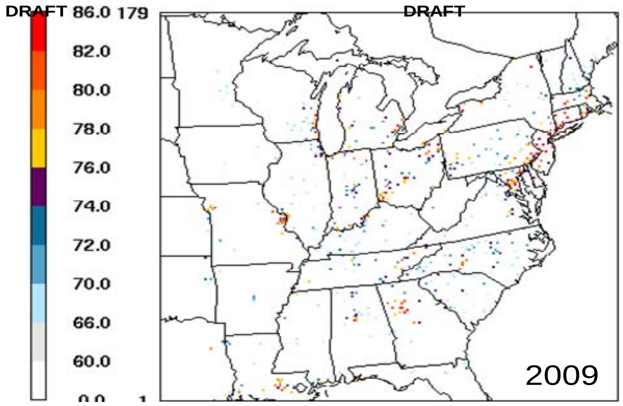
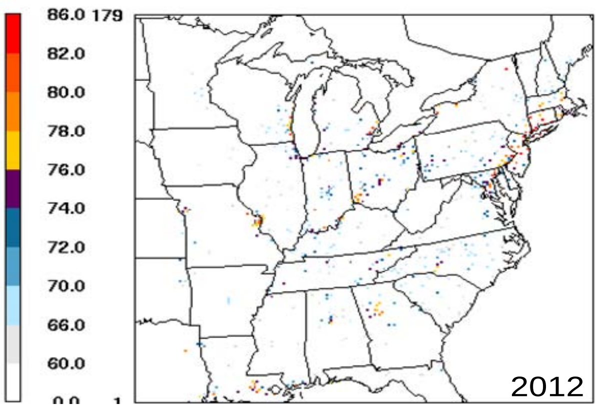
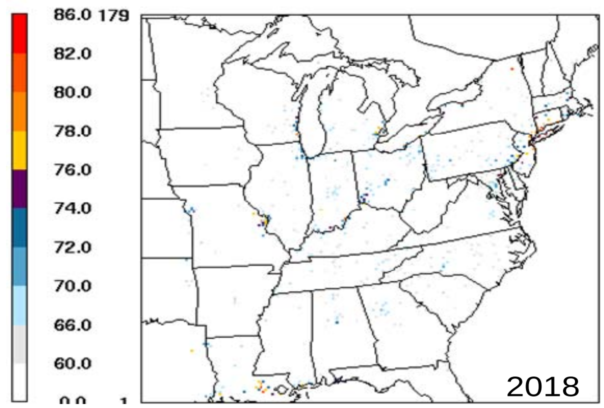
Ozone 8-Hour Concentrations

8-Hour - 0.08 ppm NAAQS (No. of Counties > NAAQS)				
	Midwest	Southeast	Northeast	Total
2009	1	1	8	10
2012	0	0	3	3
2018	0	0	0	0

8-Hour - 0.075 ppm NAAQS (No. of Counties > NAAQS)				
	Midwest	Southeast	Northeast	Total
2009	50	31	66	147
2012	30	14	45	89
2018	8	2	13	23







Based on 2005 meteorology

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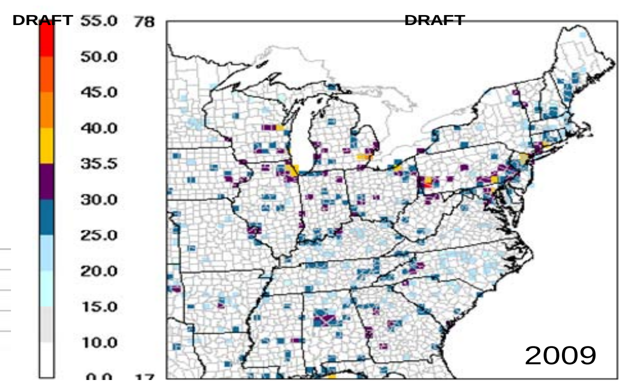
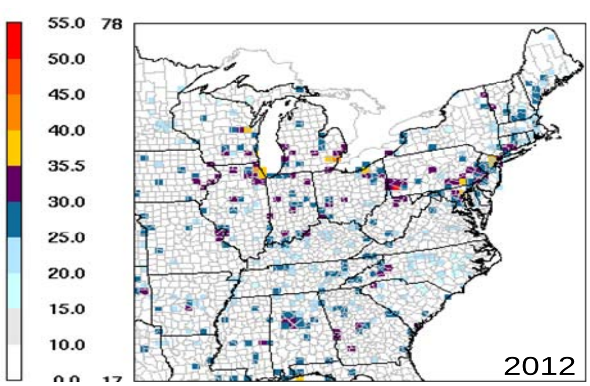
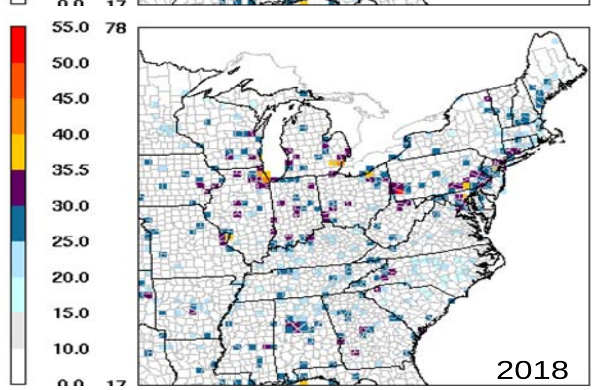
$PM_{2.5}$ Daily Concentrations

Daily (No. of Counties > NAAQS)				
	Midwest	Southeast	Northeast	Total
2009	6	0	6	12
2012	6	0	5	11
2018	6	0	4	10







Based on 2005 meteorology

DRAFT

$PM_{2.5}$ Annual Concentrations

Annual (No. of Counties > NAAQS)				
	Midwest	Southeast	Northeast	Total
2009	4	3	2	9
2012	3	1	2	6
2018	2	0	1	3

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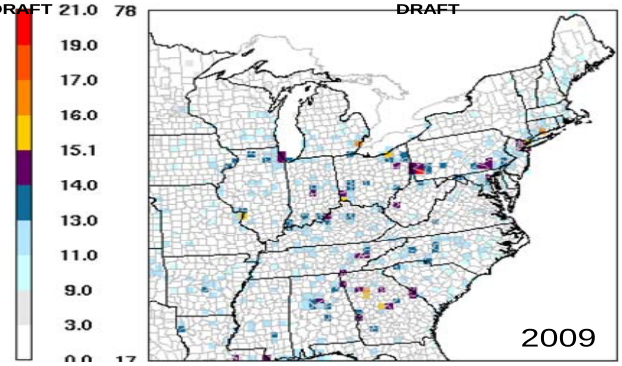
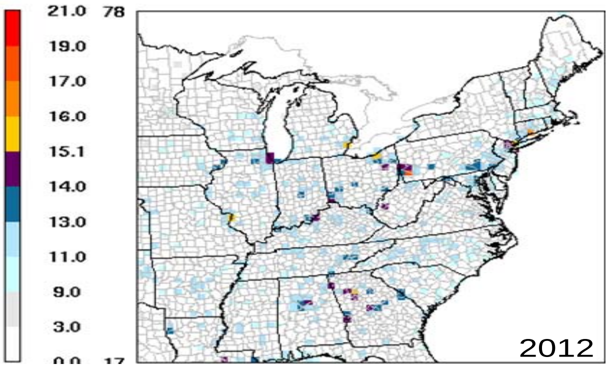
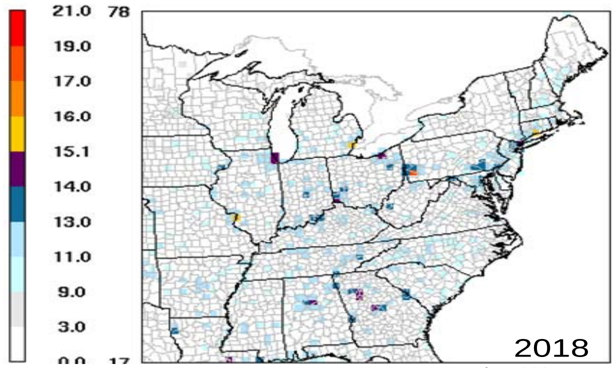


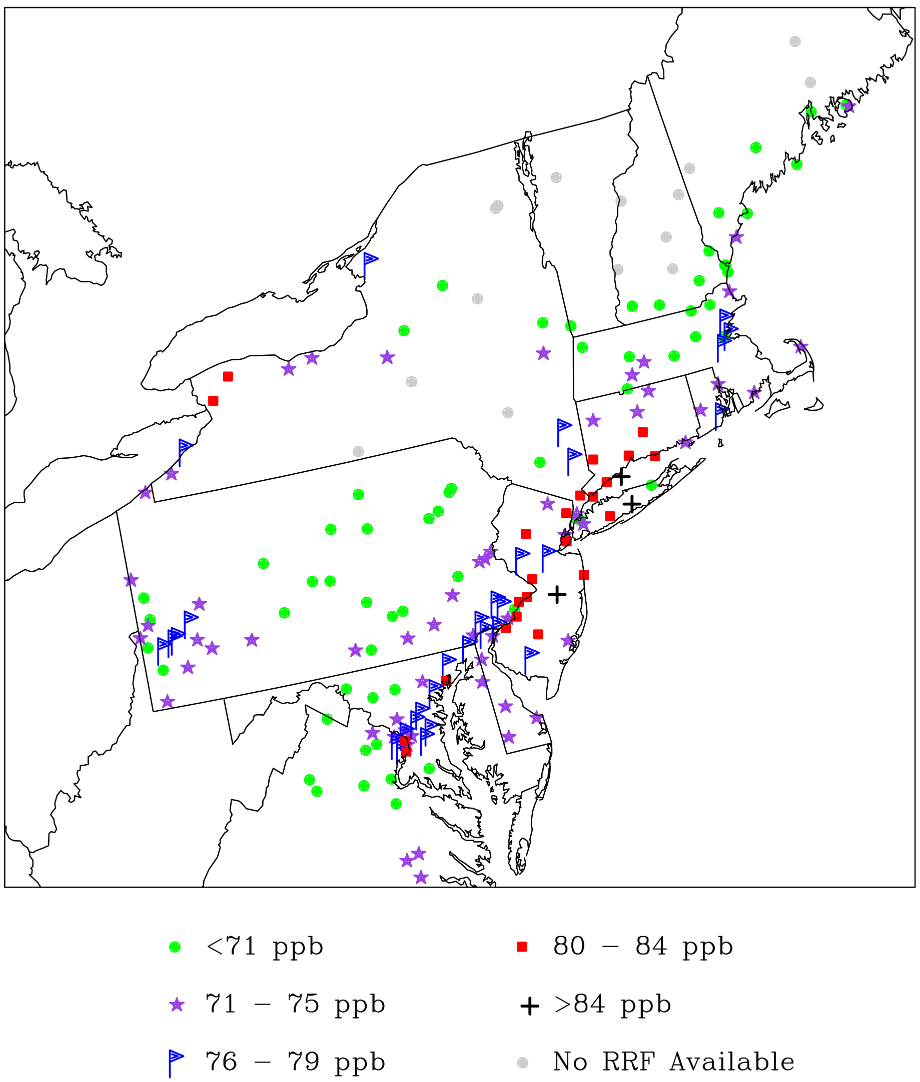




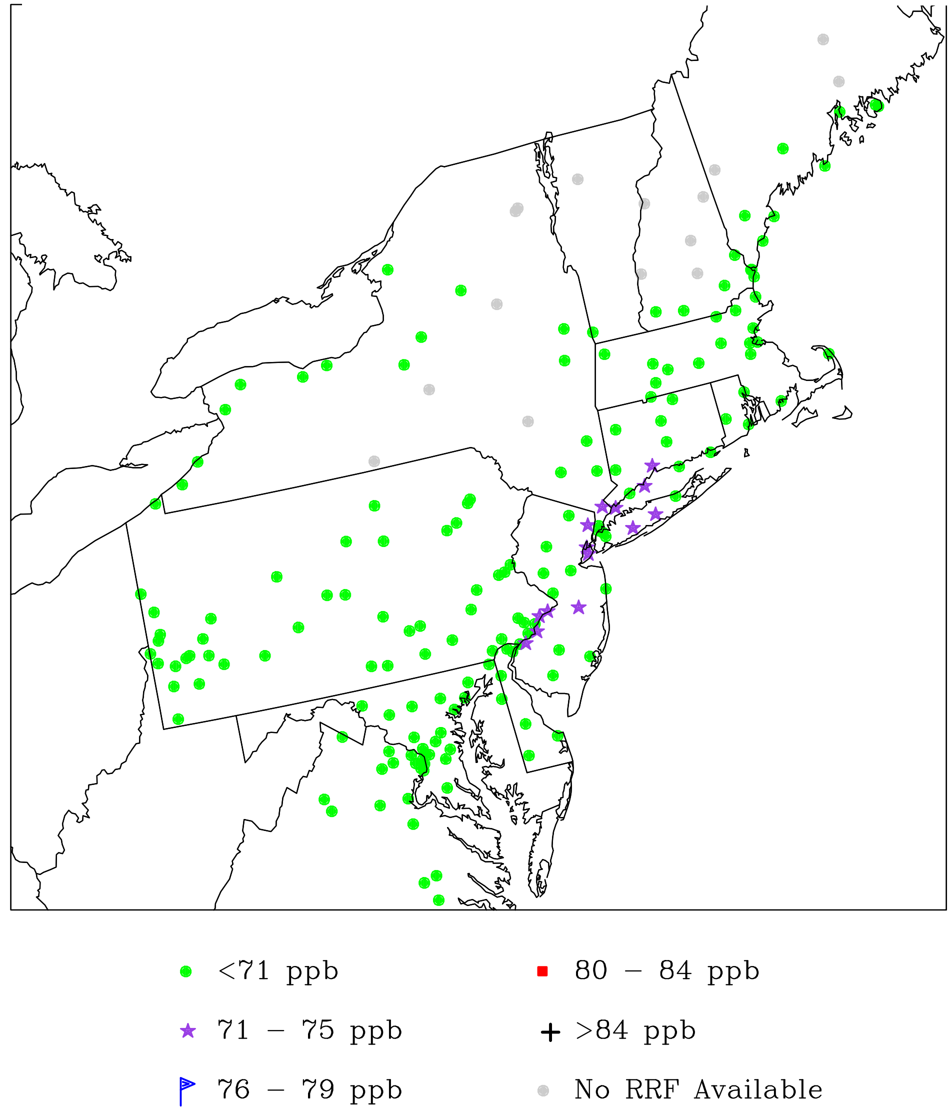
Based on 2005 meteorology

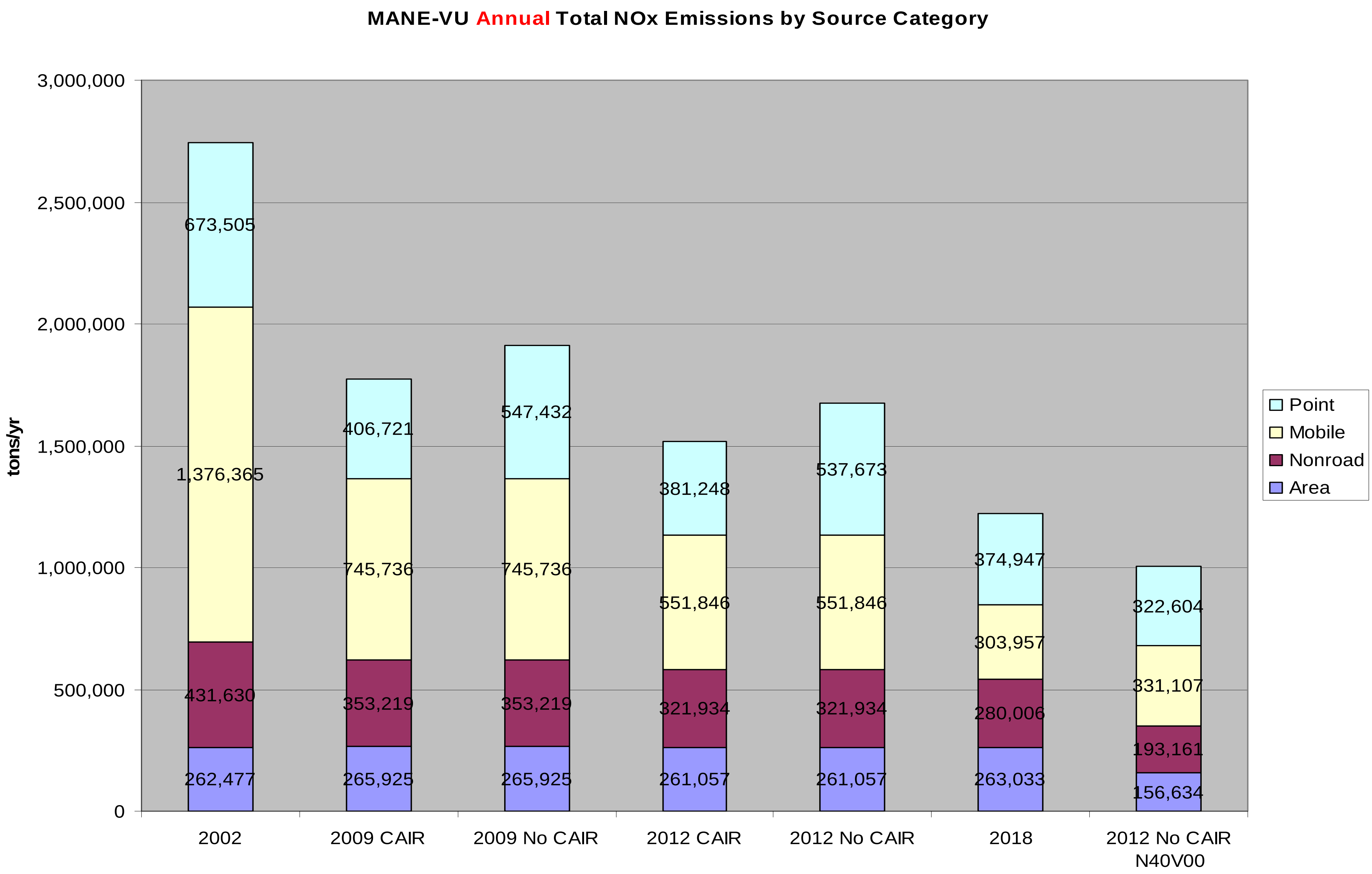
OTC Sensitivity Modeling Runs: 40% NOx Emission Reduction, All Sectors

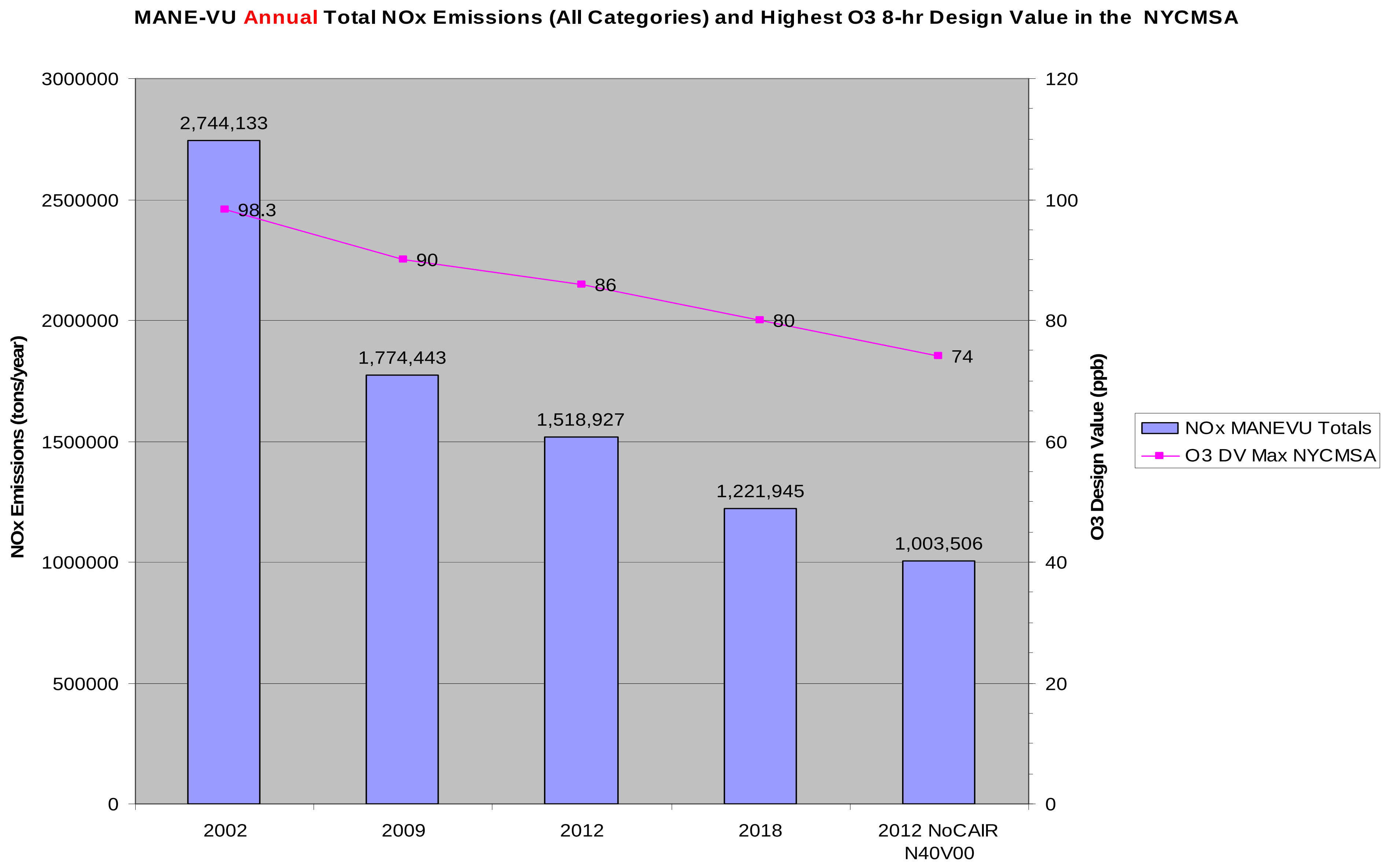
DVF 2012 BOTB/BOTW "NoCAIR"



DVF 2012 BOTB/BOTW "NOCAIR" Minus 40% Across-the-Board Anthropogenic NOx




MANE-VU Annual Total NOx Emissions by Source Category
tons/yr
3,000,000
2,500,000
2,000,000
1,500,000
1,000,000
500,000
0
673,505
1,376,365
431,630
262,477
406,721
745,736
353,219
265,925
547,432
745,736
353,219
265,925
381,248
551,846
321,934
261,057
537,673
551,846
321,934
261,057
374,947
303,957
280,006
263,033
322,604
331,107
193,161
156,634
2002
2009 CAIR
2009 No CAIR
2012 CAIR
2012 No CAIR
2018
2012 No CAIR N40V00
Point
Mobile
Nonroad
Area


MANE-VU Annual Total NOx Emissions (All Categories) and Highest O3 8-hr Design Value in the NYCMSA
3000000
2500000
2000000
1500000
1000000
500000
0
NOx Emissions (tons/year)
120
100
80
60
40
20
0
O3 Design Value (ppb)
2,744,133
1,774,443
1,518,927
1,221,945
1,003,506
98.3
90
86
80
74
2002
2009
2012
2018
2012 NoCAIR N40V00
NOx MANEVU Totals
O3 DV Max NYCMSA

Appendix V – Other Sectors

Table V-1. Status Report on OTC State Efforts to Promulgate Regulations Based on OTC 2001 Model Rules (as of May 19, 2009)

	Consumer Products	Architectural and Industrial Maintenance Coatings	Portable Fuel Containers	Mobile Equipment Repair and Refinishing	Solvent Cleaning	Additional NOx Controls	Distributed Generation Standards	State Contacts and Links to Rules
CT	Effective	Effective	Effective	Effective (similar rule)	Effective	Alternative requirements in effect	Effective	Contact: Susan Amarello 860-424-3442 http://www.ct.gov/dep/cwp/view.asp?a=2684&q=331196&depNav_GID=1619
DE	Effective See 2006 rule	Effective	See 2006 rule	Effective	Effective	Effective	Effective 1/11/06	Contact: Gene Pettingill 302-323-4542 Reg. 24, 41, 42, and 1144 http://www.dnrec.state.de.us/air/aqm_page/regs.htm http://www.dnrec.state.de.us/air/aqm_page/pro_regs.htm
DC	Effective	Effective	See 2006 rule	Effective	Effective	NOx RACT Already in place	In progress	(202) 535
ME	Effective	Effective	See 2006 rule	Effective	Effective		Effective	Contact: Jeff Crawford 207-287-2437 http://www.maine.gov/dep/air/regulations/index.htm
MD	Effective (COMAR 26.11.32)	Effective (COMAR 26.11.33)	See 2006 rule	Effective (similar rule)	Effective (similar rule)	In progress	In progress	Contact: Gene Higa 410-631-3353 PFC: Eddie Durant Consumer Products: Husain Waheed 410-537-3240 http://www.dsd.state.md.us/comar/subtitle_chapters/26_Chapters.htm
MA	Adopted CP rule (Phase II) 10/19/2007; new standards effective 1/1/2009	Rule adopted 10/19/2007; new standards effective 1/1/2009	See 2006 rule	Effective (similar rule)	Rule adopted 3/06/2009; new standards effective 9/06/2009.	Effective (similar rule)	Rule finalized 9/2005	Contacts: Consumer products; AIM Coatings; solvents: Azin Kavian azin.kavian@state.ma.us Distributed Generation: Robert.donaldson@state.ma.us Proposed regulations: http://www.mass.gov/dep/public/publiche.htm Final regulations: http://www.mass.gov/dep/air/laws/regulati.htm
NH	Adopted (Effective January 1, 2007)	Adopted (7/27/06)	See 2006 rule	Not considering	Adopted	Under review	Effective (not based on OTC model rule)	Contact: Mike Fitzgerald 603-271-6390 Solvents: http://www.des.state.nh.us/rules/env-a1200.pdf DG: http://www.des.state.nh.us/rules/env-a3700.pdf

Table V-2. Status Report on OTC State Efforts to Promulgate Regulations Based on OTC 2001 Model Rules (as of May 19, 2009)

	Consumer Products	Architectural and Industrial Maintenance Coatings	Portable Fuel Containers	Mobile Equipment Repair and Refinishing	Solvent Cleaning	Additional NOx Controls	Distributed Generation Standards	State Contacts and Links to Rules
NJ	Effective	Effective	Effective	Effective	Effective	Effective	Effective	Contacts: CP, PFCs: Judy Rand 609-984-1950 Additional NOx Controls, DG: Allan Willinger 609-633-1120
NY	Effective	Effective	See 2006 rule	Effective	Effective	Effective	In progress (Target effective date 07/01/10)	Contact: Ron Stannard 518-402-8396 CP: http://www.dec.state.ny.us/website/regs/ch3.htm (Part 235) AIM: http://www.dec.state.ny.us/website/regs/part205_new.html PFC: http://www.dec.state.ny.us/website/regs/239.htm MERR: ftp://www.dec.state.ny.us/dar/library/text228.pdf SC: http://www.dec.state.ny.us/website/regs/part226.html ANC: ftp://www.dec.state.ny.us/dar/library/xpt227.pdf
PA	Effective	Effective	See 2006 status report; Will rely on Fed PFC rule adopted by EPA on February 26, 2007. 72 FR 8427	Similar rule is already in place	Effective	Effective	Will consider	Contact: Susan Hoyle, shoyle@state.pa.us; 717-772-2329 Additional NOx Controls http://www.pabulletin.com/secure/data/vol34/34-50/2176.html MERR: http://www.pacode.com/secure/data/025/chapter129/s129.75.html SC: http://www.pacode.com/secure/data/025/chapter129/s129.63.html PFC: http://www.pacode.com/secure/data/025/chapter130/subchapAtoc.html CP: http://www.pacode.com/secure/data/025/chapter130/subchapBtoc.html AIM: http://www.pacode.com/secure/data/025/chapter130/subchapCtoc.html
RI	Effective 7/09,	Effective 7/09	See 2006 rule	Effective (similar rule)	Effective (similar rule) Updated 10.08	Will consider	Effective (similar rule)	Contact: Barbara Morin 401-222-2808
VT	Will consider	RACT**	See 2006 rule	RACT**	RACT**	RACT**	In progress	
VA	Effective	Effective	See 2006 rule	Effective	Effective			Contact: Gary Graham (804) 698-4103 gegraham@deq.virginia.gov AIM: http://www.deq.virginia.gov/air/pdf/airregs/449.pdf PFC: http://www.deq.virginia.gov/air/pdf/airregs/442.pdf MERR: http://www.deq.virginia.gov/air/pdf/airregs/448.pdf SC: http://www.deq.virginia.gov/air/pdf/airregs/447.pdf CP: http://www.deq.virginia.gov/air/pdf/airregs/450.pdf CP Info: http://www.deq.virginia.gov/air/consumerprod.html

** RACT determination required at the time of renewal of operating permit by state law

Table V-3. Status Report on OTC State Efforts to Promulgate Regulations Based on OTC 2006 Model Rules (as of May 19, 2009)

	Consumer Products (Phase II)	*Adhesives and Sealants*	*Portable Fuel Containers (w/ Kerosene)*	*Diesel Chip Reflash*	*Asphalt Paving*	*Regional Fuel*	*Additional NOx Controls*	*State Contacts and Links to Rules*
CT	*Effective*	*Effective*	*Effective*	*Developing an integrated heavy-duty diesel truck strategy*	*Rule adoption proceeding.*	*Effective statewide*	*Under evaluation as part of a multi-pollutant planning effort*	*Contact:* *Susan Amarello 860-424-3442* *http://www.ct.gov/dep/cwp/view.asp?a=2684&q=331196&depNav_GID=1619*
DE	*Effective April 11, 2009*	*Effective April 11, 2009*	*Relying on federal rule*	*Developing strategy*	*Similar rule already in effect*	*Already in effect statewide*	*Effective on July 11, 2007*	*Adhesives, PFC, Asphalt, Consumer Products: Gene Pettingill 302-323-4542* *Regional Fuel, Chip Reflash: Phil Wheeler (302) 739-9402* *Additional NOx Controls: Frank Gao (302)0323-4542* *http://regulations.delaware.gov/AdminCode/title7/1000/1100/1141.shtml#TopOfPage*
DC	*Proposed May 2007; addressing public comments*	*Proposed May 2007; addressing public comments*	*Proposed May 2007*	*No Action*	*No Action*	*No Action*	*No Action*	*Contact: Cecily Beall (202) 535-2626*
ME	*Rule adopted, Standards effective Jan 1, 2009*	*Scheduled for adoption 5/21/09*	*Draft rule under development*	*No action*	*Scheduled for public hearing 6/18/09*	*No Action*	*No Action*	*Contact: Jeff Crawford 207-287-2437* *http://www.maine.gov/dep/air/regulations/index.htm*
MD	*Proposal publication 03/31/07; Hearing 5/1/07; Final Reg Pub 06/08/07; Effective 06/18/07*	*Rule adopted February 5, 2008; new standards effective April 7, 2008.* *Single Ply Roof Amendment: Adopted 04/29/09; Published 05/22/09; Effective 06/01/09*	*Proposal publication 03/31/07; Hearing 5/1/07; Final Reg Pub 06/08/07; Effective 06/18/07*	*No action*	*Under review*	*Presently in nonattainment areas, will consider regional fuel for attainment areas*	*Distributed Generation regulation: Proposal publication 10/24/08; Hearing 11/25/08; Final Reg Pub 05/08/09; Effective 05/18/09 Partial HEDD consent order 2008.*	*Contacts:* *PFC: Eddie Durant* *Consumer Products, Adhesives: Husain Waheed* *DG: Randy Mosier* *410-537-3240*
MA	*Rule adopted 10/19/2007; new standards effective 1/1/2009*	*Rule under development.*	*Will rely on 2007 Federal PFC rule (72 FR 8427) .*	*No action*	*Rule under development.*	*Already have RFG statewide*	*Under review*	*Contacts:* *Consumer products; Adhesives and Sealants; Asphalt Paving: Azin Kavian azin.kavian@state.ma.us* *Proposed regulations: http://www.mass.gov/dep/public/publiche.htm* *Final regulations: http://www.mass.gov/dep/air/laws/regulati.htm*

Table V-4. Status Report on OTC State Efforts to Promulgate Regulations Based on OTC 2006 Model Rules (as of May 19, 2009)

	Consumer Products (phase II)	Adhesives and Sealants	Portable Fuel Containers (w/ Kerosene)	Diesel Chip Reflash	Asphalt Paving	Regional Fuel	Additional NOx Controls	State Contacts and Links to Rules
NH	Draft rule under development (on hold)	Draft rule under development (on hold)	Adopted	No action	Under review	Under consideration	Under review	Contact: Mike Fitzgerald 603-271-6390 Solvents: http://www.des.state.nh.us/rules/env-a1200.pdf DG: http://www.des.state.nh.us/rules/env-a3700.pdf Send annual date code update information to: airfiles@des.nh.gov
NJ	Adopted 10/30/08	Adopted 10/30/08	Adopted 10/30/08	No action	Adopted 3/20/09	RFG in place state wide	Adopted 3/20/09	http://www.state.nj.us/dep/aqm/ Contacts: CP, PFCs, Adhesives: Judy Rand 609-984-1950. Asphalt Paving: Stella Oluwaseun-Apo 609-777-0430 Diesel Chip Reflash: John Gorgol 609-292-1413 Additional NOx Controls: Allan Willinger 609-633-1120
NY	Proposed Hearings 7/09	In progress	Adopted 06/30/09	Evaluating court decision	In progress	Under consideration	In progress	Contact: Ron Stannard 518-402-8396
PA	Final rulemaking scheduled for Environmental Quality Board consideration June 16, 2008; Anticipated effective date for new categories is Jan 1, 2009	Proposed Rulemaking schedule for Environmental Quality Board consideration August 17, 2008; Anticipated effective date is May 1, 2009	Will rely on Fed PFC rule adopted by EPA on February 26, 2007. 72 FR 8427	No plans to pursue at this time.	Under consideration	Under consideration	Cement Kiln and Glass Furnace regulations' public comment periods close June 23, 2008; Anticipated effective date is May 1, 2009	Contact: Susan Hoyle 717-772-2329 **shoyle@state.pa.us** www.depweb.state.pa.us/pubpartcenter/site/default.asp www.pacode.com/ www.pabulletin.com/
RI	Rule Adopted May 2009, limits effective 7/1/09	Rule Adopted May 2009, limits effective 7/1/09	Will rely on federal rule.	No plans to pursue	Hearing on rule 2/09, limits will be effective 5/10	RFG in place state wide	No plans at this time to implement this measure.	Contact: Barbara Morin 401-222-2808 barbara.morin@dem.ri.gov
VT	No plan to adopt	Plan to pursue	Plan to pursue	Plan to pursue depending on legal basis	Considering	Under consideration, would adopt if truly regional	No plans at this time to implement this measure.	
VA	Notice of intended regulatory action	Notice of intended regulatory action	Notice of intended regulatory action	No current plans to pursue.	No current plans to pursue.	No current plans to pursue.	No current plans to pursue.	Contact: Gary Graham (804) 698-4103 gegraham@deq.virginia.gov

APPENDIX 7

Evaluation of Control Options for Industrial, Commercial and Institutional (ICI) Boilers

Technical Support Document (TSD)

Ozone Transport Commission (OTC) / Lake Michigan Air Directors Consortium (LADCO)

DRAFT

5/25/10

Evaluation of Control Options for ICI Boilers

Technical Support Document (TSD)

Ozone Transport Commission (OTC) / Lake Michigan Air Directors Consortium

Executive Summary

In December 2005, Environmental Commissioners from Northeast and Midwest States initiated a state collaborative process. Their goal was to coordinate emission control programs to meet the current National Ambient Air Quality Standards (NAAQS) and to prepare for addressing the upcoming, tighter NAAQS. Pursuant to the state collaborative discussions, a staff-level workgroup was formed in 2006 to evaluate control options for industrial, commercial, and institutional (ICI) boilers.

According to EPA's National Emissions Inventory (NEI), ICI boilers emit 6% of total NOx emissions (1.4 million tons in 2002) and 13% of total SO_2 (2.0 million tons in 2002). ICI boilers represent the third largest source sector of NOx emissions (after mobile sources and electric generating units (EGUs) and the second largest source sector of SO_2 emissions (after EGUs).

After extensive review of technology-based control options and associated costs, the staff-level workgroup developed a 3-part control program for federal action on ICI boilers: (1) performance-based nitrogen oxides (NOx) and sulfur dioxide (SO_2) emission limitations, (2) annual boiler tune-ups[1] (units $\geq$ 25 million British thermal units per hour (MMBtu/hr)), and (3) annual emissions reporting (units $\geq$ 25 MMBtu/hr).

To maximize compliance flexibility for sources, the emission limitations could be achieved in two phases with Phase I compliance dates in the 2012-2015 timeframe, and Phase II compliance dates in the 2015-2018 timeframe.

[1] An alternative to boiler tune-ups is to require boiler owners/operators to manage combustion using continuous combustion monitoring, plus fuel and combustion air flow trim equipment.

NOx control options for **units ≤ 100 MMBtu/hr** consist of:

- Phase I: Combustion tuning for all gas and oil-fired units and for certain coal-fired-units 25-100 MMBtu/hr.
- Phase II:
    - Low-NOx burners and/or flue gas recirculation (FGR) for all gas- and oil-fired units;
    - Combustion tuning and/or selective non-catalytic reduction (SNCR) for certain coal-fired units ≥50 MMBtu/hr and ≤ 100 MMBtu/hr; and
    - Combustion tuning or SNCR for all wood-fired units and non-fossil solid fuel-fired units ≥ 50 MMBtu/hr and ≤ 100 MMBtu/hr.

NOx control options for **units > 100 MMBtu/hr** consist of:

- Phase I:
    - Low-NOx burners for all gas- and oil-fired units;
    - Low-NOx burners and/or combustion modifications for most coal-fired units;
    - Selective catalytic reduction (SCR) or SNCR for certain coal-fired units; and
    - Combustion tuning or SNCR for all wood-fired units and non-fossil solid fuel-fired units.
- Phase II: Post-combustion controls for all coal-, wood-, and non-fossil fuel-fired units.

SO_2 control options consist of:

- Oil-fired units: Lower sulfur fuel oil
- Coal-fired units: Lower sulfur fuel and/or combustion modifications in Phase I, and post-combustion controls in Phase II

Analysis of expected control costs indicate NOx cost effectiveness values ranging from $2,700 - $12,000 per ton in 2008$ (for 100 MMBtu/hr residual oil and coal-fired units) to $200 - $2,000 per ton in 2008$ (for 750 MMBtu/hr residual oil and coal-fired units), and SO_2 cost effectiveness values ranging from $2,000 - $8,000 per ton in 2008$ (for 100 MMBtu/hr units) to $1,300 - $3,800 per ton in 2008$ (for 750 MMBtu/hr units). These values are comparable to (or slightly higher than) many existing federal control programs.

Table of Contents

I. Introduction

A. Purpose

To provide the U.S. Environmental Protection Agency (EPA) with an evaluation of an emission control program, including nitrogen oxides (NOx) and sulfur dioxide (SO_2) emission limitations, for industrial, commercial, and institutional (ICI) boilers.

B. Context

Reductions in NOx and SO_2 emissions are needed to help states attain and maintain the national ambient air quality standards for ozone and fine particulate matter ($PM_{2.5}$), and make further progress in reducing regional haze. This evaluation addresses ICI boilers, which are a major source of these pollutants. Further discussions with EPA will be necessary to determine an appropriate mechanism for implementing the emissions control program.

C. Rationale

Action is necessary to reduce NOx and SO_2 emissions from ICI boilers for the following reasons: (1) ICI boilers are an important source of NOx and SO_2 emissions, (2) reductions in ICI boiler emissions are cost effective, and (3) reductions in ICI boiler emissions are expected to provide regional and local air quality benefits - i.e., many ICI boilers are located in (or near) urban/industrial nonattainment areas and have relatively shorter stacks compared to large Electrical Generating Units (EGUs).

II. Background

A. Description of Air Quality Problems

In the Northeast and Midwest, there are 140 counties classified as nonattainment for the 1997 8-hour ozone standard and 123 for the 1997 annual $PM_{2.5}$ standard. Modeling-based projections indicate that most (but not all) of these nonattainment areas are expected to meet the federal air quality standards for ozone and $PM_{2.5}$ by their attainment dates.

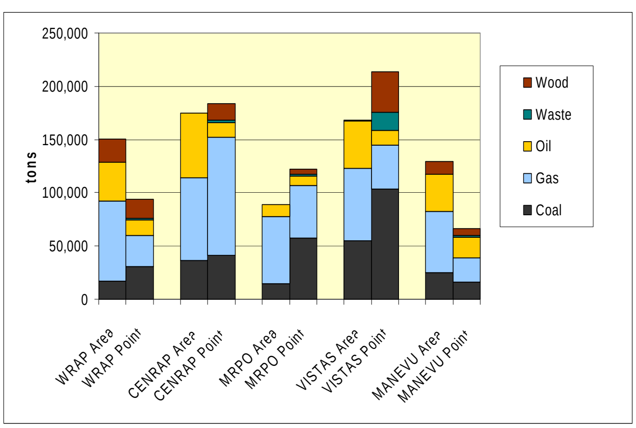
Because EPA has tightened the daily $PM_{2.5}$ standard in 2006 and the 8-hour ozone standard in 2008 nonattainment will remain an issue for the foreseeable future. Current modeling-based projections indicate that many areas are not likely to meet these new standards by their respective attainment dates (i.e., 2014 for the 2006 daily $PM_{2.5}$ standard and 2013-2020 for the 2008 8-hour ozone standard).

In addition, there are 14 federal Class I areas in the Northeast and Midwest where visibility impairment due to regional haze is a continuing problem. Modeling projections indicate that visibility impairment in several Class I areas may remain above levels established as presumptive uniform rates of improvement for 2018. Thus, further progress is needed to achieve the national goal of restoring natural visibility in these Class I areas.
In summary additional national, regional and local emission reductions are needed both to attain air quality standards and to make progress in meeting regional haze goals.

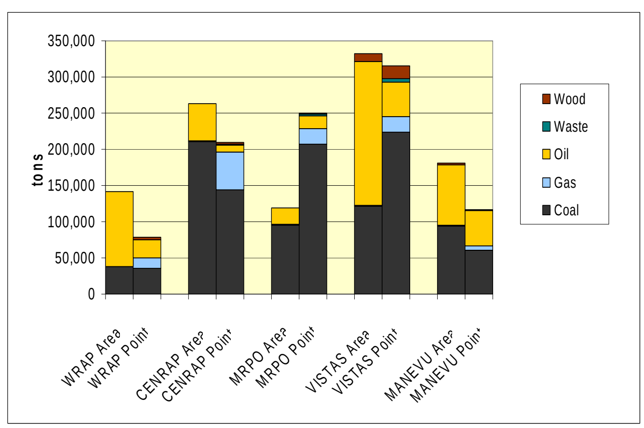
B. Importance of ICI Boilers

Nationally, emissions from the ICI boiler sector make-up approximately 6% (1.4 million tons/year) of total NOx and 13% (2.0 million tons/year) of total SO_2 emissions based on the limited emissions data available at this time (2002 National Emission Inventory). With the additional EGU SO_2 and NOx controls pursuant to federal EGU control programs, the share of ICI boilers in the residual inventories will be larger given that the impacts of non-EGU BART and non-EGU RACT programs have been limited to date. Figure 1 shows 2002 regional area and point source ICI sector emissions by fuel type.

Figure 1. Regional ICI Boiler Emissions by Fuel Type (2002)



NOx

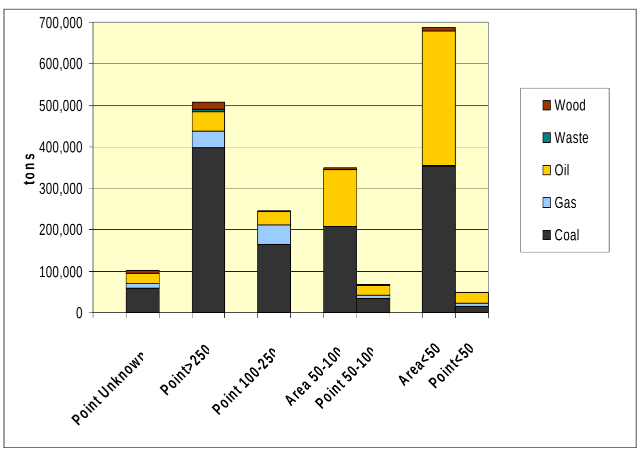


SO2

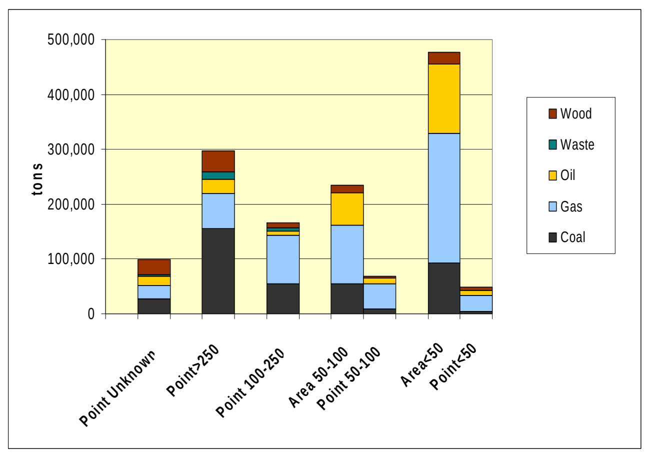
The best available emissions data in base year 2002 for the Northeast and Midwest indicate that ICI boiler point sources make-up approximately 6% and 3%, respectively, of regional NOx emissions and approximately 10% and7%, respectively, of regional SO_2 emissions. ICI boilers are the next largest source category after EGUs (21% of NOx emissions, 70% of SO_2 emissions) and mobile sources (55% of NOx emissions).

In the case of the Lake Michigan Air Directors Consortium (LADCO) States, coal-fired ICI boilers are most important (60% of NOx and 90% of SO_2 total ICI sector emissions) and emissions are concentrated in the largest boiler sizes (86% NOx, 93% SO_2 from boilers > 100 million British thermal units per hour (MMBtu/hr)). Figure 2 below shows the ICI sector emissions in size categories by fuel type:

Figure 2. Regional ICI Boiler Emissions by Size Range and Fuel Type (2002)



NOx



SO2

In the Northeast (MANE-VU region), 72% of NOx emissions from ICI boiler point sources come from oil and gas-fired units. These point source emissions are divided evenly among the size categories (52% of NOx emissions from oil-fired point sources are <100 MMBtu/hr, and 50% from gas-fired sources are <100 MMBtu/hr). In addition, ICI boiler area sources are estimated to account for 66% of total NOx emissions in the Northeast from this sector. Given the significance of oil- and gas-firing for both smaller (< 100 MMBtu/hr) and larger boilers (> 100 MMBtu/hr), emission control requirements are recommended for these fuel types and size ranges.

III. <u>Emissions Control Program</u>

A. Emissions Control Options

The Workgroup evaluated a two-phase control program in order to maximize compliance flexibility for sources. For coal-fired ICI boilers, the Phase I NOx and SO_2 compliance dates evaluated were between 2012-2015, and the Phase II NOx and SO_2 compliance dates evaluated were between 2015-2018. For the low-sulfur fuel-oil strategy, the Phase I SO_2 compliance dates evaluated were 2012-2014, and the Phase II SO_2 compliance dates evaluated were 2014-2018.

NOx Control Options: Table 1 provides a summary of the control options considered for NOx as a function of fuel type, boiler type, and boiler size. For certain size categories and fuels, there were not evaluated due to small or non-existent boiler populations in the Northeast and Midwest emissions inventory.

NOx control options for **units ≤ 100 MMBtu/hr** consist of:

- Phase I: Combustion tuning for all gas and oil-fired units and for certain coal-fired-units 25-100 MMBtu/hr.
- Phase II:
  - Low-NOx burners and/or flue gas recirculation (FGR) for all gas- and oil-fired units;
  - Combustion tuning and/or selective non-catalytic reduction (SNCR) for certain coal-fired units ≥50 MMBtu/hr and ≤ 100 MMBtu/hr; and
  - Combustion tuning or SNCR for all wood-fired units and non-fossil solid fuel-fired units ≥ 50 MMBtu/hr and ≤ 100 MMBtu/hr.

NOx control options for **units > 100 MMBtu/hr** consist of:

- Phase I:
  - Low-NOx burners (LNB) for all gas- and oil-fired units;
  - Low-NOx burners and/or combustion modifications for most coal-fired units;
  - Selective catalytic reduction (SCR) or SNCR for certain coal-fired units; and
  - Combustion tuning or SNCR for all wood-fired units and non-fossil solid fuel-fired units.
- Phase II: Post-combustion controls for all coal-, wood-, and non-fossil fuel-fired units.

Table 1. NOx Control Options

Fuel Type	Phase	Boiler Size (MMBtu/hour)		
		< 50	50-100	> 100
Gaseous Fuels (natural gas, refinery gas, blast furnace gas, coke oven gas)	Phase I	Comb. Tuning	Comb. Tuning	LNB
	Phase II	LNB / FGR/ LNB + FGR	LNB / FGR/ LNB + FGR	LNB / FGR / LNB + FGR
Distillate Oil (#1.#2)	Phase I	Comb. Tuning	Comb. Tuning	LNB
	Phase II	LNB / FGR/ LNB + FGR	LNB / FGR/ LNB + FGR	LNB / FGR / LNB + FGR
Residual Oil (#4,#5,#6)	Phase I	Comb. Tuning	Comb. Tuning	LNB
	Phase II	LNB / FGR	LNB / FGR	LNB / FGR
Coal - Wall	Phase I			LNBO(1)/LNBO + SNCR
	Phase II			Enhanced Monitoring (2) + Micronized coal use + LNBO/LNBO + SCR/SCR
Coal - Tangential	Phase I			LNB/LNC1/LNC2 (3)
	Phase II			Enhanced Monitoring (4) + Micronized coal use + LNC3/LNC3 + SCR/SCR
Coal - Cyclone	Phase I			OFA + SCR/SCR
	Phase II			OFA + SCR/SCR
Coal - Stoker	Phase I		Comb. Tuning	Combustion Tuning + SNCR (5)
	Phase II		Comb. Tuning +SNCR	Comb. Tuning + SNCR (5)
Coal – FBC (7)	Phase I		Comb. Tuning	Gas Cofiring / SNCR (6)
	Phase II		SNCR	SNCR
Wood and Non-Fossil Solid Fuel	Phase I		Comb. Tuning	Comb. Tuning / SNCR
	Phase II		Comb. Tuning/ SNCR	Comb. Tuning / SNCR

Notes – In gray boxes, no evaluation was performed due to small or non-existent boiler population in the Northeast & Midwest emissions inventory. "/" indicates "or" while "+" indicates "and" unless otherwise footnoted.

(1) LNBO means Low NOx Burners (LNB) with Over Fire Air (OFA).

(2) Enhanced monitoring of coal and air flow is recommended by several vendors of neural networks. These systems measure multiple operating parameters and use the information to adjust variations in fuel quality, equipment performance, and environmental conditions. Hot spots are removed during testing and later the boiler is operated within the parameters recommended by the neural network. Micronized coal will require a newer ball mill. A combination of enhanced monitoring, micronized coal use, and LNBO should achieve NOx limit of 0.14 lb/MMBtu w/o Selective Catalytic Reduction (SCR).

(3) Depending on coal type, LNB or a combination of LNB with close-coupled OFA (LNC1) or LNB with separated OFA (LNC2) should achieve a limit of 0.30 lb/MMBtu.

(4) Enhanced monitoring and micronized coal use is described above. LNC3 is a LNB with a combination of LNC1 and LNC2. A combination of enhanced monitoring, micronized coal use and LNC3 should achieve NOx limit of 0.12 lb/MMBtu w/o Selective Catalytic Reduction (SCR).

(5) Most stokers use large excess air to avoid overheating of grate. By controlling excess air and using minimum amount of Selective Non-Catalytic Reduction (SNCR), NOx limit of 0.30 can be achieved. To achieve a limit of 0.22, higher level of ammonia or urea will be needed.

(6) If gas is available on site it can be used in place of SNCR.

(7) FBC means Fluidized Bed Combustion.

SO_2 Control Options: The control options considered for SO_2 consist of the following

Gaseous Fuels: Gaseous fuels are treated at the source (e.g., coke plant) to remove hydrogen sulfide (H_2S) and mercaptans prior to combustion.
Fuel Oils: Fuel oils are de-sulfurized at the refinery.
Coal: Fuel blending and fuel switching, direct sorbent injection, and post – combustion control, such as dry or wet flue gas desulfurization.

B. Emission Limits

The emissions limitations in Tables 2 and 3 reflect: (1) application of available, demonstrated control technologies, and (2) reasonable estimated control costs (i.e., consistent with the costs of other existing control programs). The development of these limits also takes into account the available (limited) emission inventories for ICI boilers in the affected states and recent state actions.

A boiler owner/operator may request an alternative emission limit or compliance date based on a source-specific engineering analysis conducted in accordance with a state- or EPA-approved methodology (e.g., BART guidelines) which addresses the technological and economic feasibility of reducing NOx and SO_2 emissions. Alternative emission limits would include any state-approved emission limitations established pursuant to BART.

The Phase II NOx limits for gas and oil units reflect limits established in the Ozone Transport Commission (OTC) Addendum to Resolution 06-02, adopted by the Commission on November 15, 2006. The Addendum also identified similar limits for coal-fired units, including a NOx limit of 0.30 lb NOx/MMBtu or 50% NOx reduction from uncontrolled NOx emissions for ICI boilers in the 25-100 MMBtu/hr size range. The Phase II limits for oil units reflect a course of action by the Northeast/Mid-Atlantic states to pursue the adoption and implementation of a strategy to reduce the sulfur content of fuel oil in a phased approach by 2018 to meet regional haze reasonable progress goals for the MANE-VU Class I areas. When fully implemented, the projected total emission reductions from the 2006 resolution NOx limits in the OTC states is 37.7 tons per summer day from point sources, and 69.5 tons per day from area sources. These reductions are additional to NOx limits in the OTC 2001 model rule for ICI boilers, which was projected to achieve a reduction of 33.7 summer tons per day of NOx in the OTC region in 2007. The SO_2 projected emission reductions from full implementation of the low-sulfur fuel oil strategy will be more than 200,000 tons per year in the Northeast/Mid-Atlantic states – nearly a 35% reduction.

Given the overwhelming significance of large (> 100 MMBtu/hr) coal-fired boilers, emission control requirements were evaluated for this fuel type and size range. Additionally, given the importance of SO_2 emissions with respect to particulate sulfate (a major component to $PM_{2.5}$ and regional haze in the eastern half of the U.S.), emission control requirements were also evaluated for smaller (50 – 100 MMBtu/hr) coal-fired boilers.

In pursuing a control program for ICI boilers, EPA may find it necessary and appropriate to include further control requirements (e.g., lower emission limits and broader size ranges). In particular, fuel usage inventories show coal-fired boilers < 100 MMBtu/hr contribute significant NOx emissions. At this time, due to limited inventory information, the Workgroup has not evaluated NOx Phase II emission limits for coal-fired boilers < 50 MMBtu/hr; however, there are potentially appropriate control technologies identified for coal-fired and non-fossil fuel-fired ICI boilers in the 50-100 MMBtu/hr and < 50 MMBTU/hr size categories. EPA should use the emissions information gained from the reporting program to establish appropriate emission limits for these boilers.

Table 2. NOx Emission Limitations

Fuel Type	Phase	Boiler Size (MMBtu/hour)		
		< 50	50-100	> 100
Gaseous Fuels (natural gas, refinery gas, blast furnace gas, coke oven gas)	Phase I	Comb. Tuning	Comb. Tuning	0.10 or 50%
	Phase II	0.05 - 0.10 or 50%	0.05 - 0.10 or 60%	0.05 - 0.10 or 60%
Distillate Oil (#1.#2)	Phase I	Comb. Tuning	Comb. Tuning	0.10 or 50%
	Phase II	0.08 - 0.10 or 50%	0.08 - 0.10 or 60%	0.08 - 0.10 or 60%
Residual Oil (#4,#5,#6)	Phase I	Comb. Tuning	Comb. Tuning	0.20 or 60%
	Phase II	0.20 or 50%	0.20 or 60%	0.20 or 70%
Coal - Wall	Phase I			0.30
	Phase II			0.10 - 0.14
Coal - Tangential	Phase I			0.30
	Phase II			0.10 - 0.12
Coal - Cyclone	Phase I			0.19
	Phase II			0.19
Coal - Stoker	Phase I		Comb. Tuning	0.30
	Phase II		0.30	0.22
Coal – FBC	Phase I		Comb. Tuning	0.15
	Phase II		0.08	0.08
Wood and Non-Fossil Solid Fuel	Phase I		Comb. Tuning	0.30
	Phase II		0.30	0.22

Note – In gray boxes, no evaluation was performed due to small or non-existent boiler populations in the Northeast and Midwest emissions invnetory.

Table 3. SO_2 Emission Limitations

Fuel Type	Phase	Boiler Size (MMBtu/Hour)			
		< 50	50-100	>100-250	> 250
Gaseous Fuels (coke oven gas)	Phase I			Treated COG with 95%S compounds removed	Treated COG with 95%S compounds removed
	Phase I			Treated COG with 95%S compounds removed	Treated COG with 95%S compounds removed
Distillate Oil (#1, #2)	Phase I	0.05%S (500ppm), or 0.05 lb/MMBTU	0.05%S (500ppm), or 0.05 lb/MMBTU	0.05%S (500ppm), or 0.05 lb/MMBTU	0.05%S (500ppm), or 0.05 lb/MMBTU
	Phase II **Northeast States Inner Zone**	Further reduce Sulfur content to 15ppm by 2016	Further reduce Sulfur content to 15ppm by 2016	Further reduce Sulfur content to 15ppm by 2016	Further reduce Sulfur content to 15ppm by 2016
	Phase II **Elsewhere**	Further reduce Sulfur content to 15ppm by 2018	Further reduce Sulfur content to 15ppm by 2018	Further reduce Sulfur content to 15ppm by 2018	Further reduce Sulfur content to 15ppm by 2018
Residual Oil (#4, #5, #6)	Phase I	0.5%S (or 0.54 lb/MMBTU)	0.5%S (or 0.54 lb/MMBTU)	0.5%S (or 0.54 lb/MMBTU)	0.5%S (or 0.54 lb/MMBTU)
	Phase II **Northeast States Inner Zone**	#4 Fuel Oil 0.25%S no later than 2012	#4 Fuel Oil 0.25%S no later than 2012	#4 Fuel Oil 0.25%S no later than 2012	#4 Fuel Oil 0.25%S no later than 2012
		#6 Fuel Oil 0.3-0.5% no later than 2012	#6 Fuel Oil 0.3-0.5%S no later than 2012	#6 Fuel Oil 0.3-0.5%S no later than 2012	#6 Fuel Oil 0.3-0.5%S no later than 2012
	Phase II **Elsewhere**	#4 Fuel Oil 0.25-0.5%S no later than 2018	#4 Fuel Oil 0.25-0.5%S no later than 2018	#4 Fuel Oil 0.25-0.5%S no later than 2018	#4 Fuel Oil 0.25-0.5%S no later than 2018
		#6 Fuel Oil 0.5%S no later than 2018	#6 Fuel Oil 0.5%S no later than 2018	#6 Fuel Oil 0.5%S no later than 2018	#6 Fuel Oil 0.5%S no later than 2018
Coal (and other solid fuels)	Phase I		2.0 lb/MMBtu or 30% reduction**	1.2 lb/MMBtu (1) or 85% reduction**	0.25 lb/MMBtu or 85% reduction**
	Phase II		2.0 lb/MMBtu or 30% reduction**	0.25 lb/MMBTU or 85% reduction**	0.25 lb/MMBTU or 85% reduction**

* COG means Coke Oven Gas.
**= % reduction based on uncontrolled emissions in base year (2002)
(1) Limit can be met by a combination of switching to low-sulfur coal / fuel blending plus direct sorbent injection (DSI) to achieve additional 40% reduction.

Compliance demonstration with the NOx and SO_2 emission limits should be based upon the average of emissions over each calendar day if a continuous emissions monitoring system (CEMS) is used. If there is no CEMS used on the equipment or source operation, then compliance with the emission limits should be based on the average of three one-hour tests, each test performed over a consecutive 60-minute period.

If a CEMS is installed on the equipment or source operation, then the average NOx emission rate should be calculated using data from such a system for the NOx concentration in the flue gas and either the flue gas flow rate or the fuel flow rate. To calculate the emission rate using the NOx concentration and fuel flow rate, the conversion procedure set forth in 40 CFR 75, Appendix F, or an approved alternative procedure should be used.

C. Boiler Tune-Ups

Poorly operated or maintained boilers waste fuel and result in excess air pollution. Boiler tune-ups provide for more efficient boiler operation, are inexpensive, reduce fuel consumption**,** provide a net savings, and reduce air pollution.

All fossil-fuel fired units with rated capacity equal to or greater than 25 MMBtu/hr should perform boiler tune-ups on an annual basis. If the owner or operator is using the scheduled tune-up procedures provided by the manufacturer, then they will already be meeting the tune-up requirement. New York Department of Environmental Conservation's (NYDEC's) Air Guide-33 (Small Boiler Tune-Up Requirements for NOx RACT Compliance) and ASME/ANSI Boiler Test Code 4.1 are examples of two methods suggested for those owners or operators that choose to have tune-up procedures written by an approved specialist. Air Guide-33 also sets forth the recordkeeping requirements for boiler tune-ups.

Alternatively, continuous combustion monitoring, plus fuel and combustion air flow trim equipment, could be used to manage combustion. The parameters monitored on a continuous basis, at a minimum, include the fuel flow, combustion air flow, and the excess oxygen (O_2) and carbon monoxide (CO) in the flue gas. Initially, the source performs a typical tune-up to establish operating parameters for the continuous system. The parameters tested during the tune-up include the fuel flow, combustion air flow, and flue gas excess O_2, CO, and NO_x over the expected load range. An annual tune-up is performed thereafter to check the combustion balance and trim system operation. The combustion monitoring system, at a minimum, consists of combustion gas analyzer equipment operated and maintained according to the manufacturer's specifications. For units with multiple burners and combustion air ports, multiple fuel flow and combustion air flow monitors may be required to trim combustion.

D. Emissions Reporting

All fossil-fuel fired units with rated capacity equal to or greater than 25 MMBtu/hr should provide the following information electronically on an annual basis: total annual fuel consumption by fuel type, results of any fuel analyses, and results of any emission measurements, including stack tests and emission monitors. It is expected that EPA will establish and maintain a national, electronic database with this information.

Any boiler with a rated capacity less than 100 MMBtu/hr firing #2 fuel oil should conduct stack tests once every five years to demonstrate compliance with the NOx limits. Any boiler with a rated heat input capacity equal to or greater than 50 MMBtu/hr, but less than 100 MMBtu/hr, firing #4 fuel or #6 fuel oil should conduct stack tests once every two years to demonstrate compliance with the nitrogen oxides limit. Any boiler with a rated capacity greater than 100 MMBtu/hr firing #4 fuel oil or #6 oil should install a NOx CEMS. Any boiler with a rated capacity greater than 250 MMBtu/hr firing #2 fuel oil should install a NOx CEMS.

Current state and federal emissions inventories are incomplete for ICI boilers. The requested information will improve characterization of this source sector and will allow the development of appropriate and effective air quality management programs for all sizes of ICI boilers.

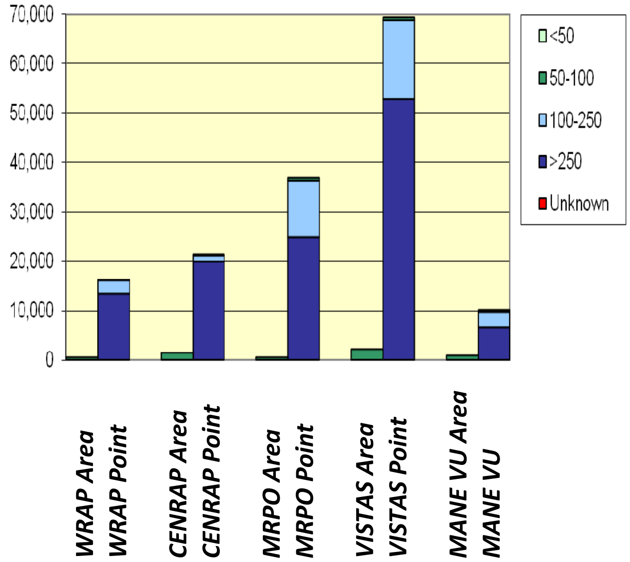
IV. <u>Emissions Reduction Analysis</u>

Nationwide, NO_x emissions from ICI boilers in Phase II will be reduced by 0.6 million tons (about 27% from baseline levels). The reductions will come more or less equally from gas-fired area sources (28% of the reduction), coal-fired point sources (24% of the reduction), and gas-fired point sources (23% of the reduction). The remaining 25% of the reductions will come from other fuel combustion by point and area sources. Figure 3 shows the emission reductions from coal-fired boilers for the Phase II limits. Figure 4 shows the emission reductions from oil and natural gas-fired boilers for the Phase II limits.

Nationwide, SO_2 emissions from ICI boilers in Phase II will be reduced by 1.1 million tons (about 55% from baseline levels). About 44% of the reduction will be from coal-fired point sources. Another 36% of the reduction will be from oil-fired area sources. The remaining 20% of the reductions will come from other fuel combustion by point and area sources.

Figure 3. Regional Emission Reductions (tons/yr) from Coal-fired Boilers by Boiler Size in MMBtu/hr

NOx



SO_2

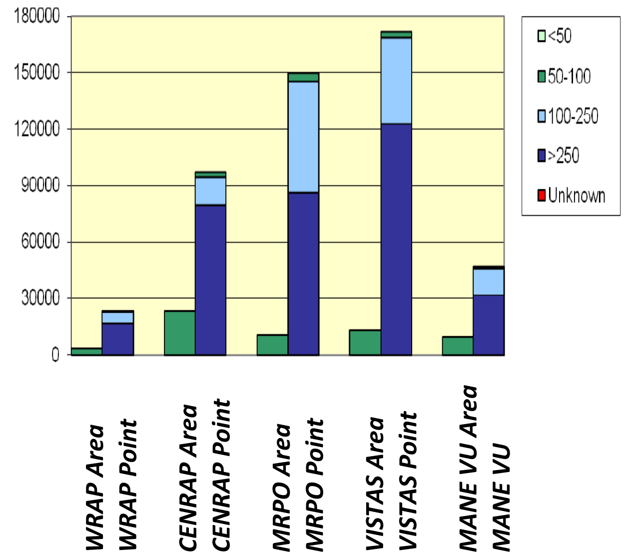
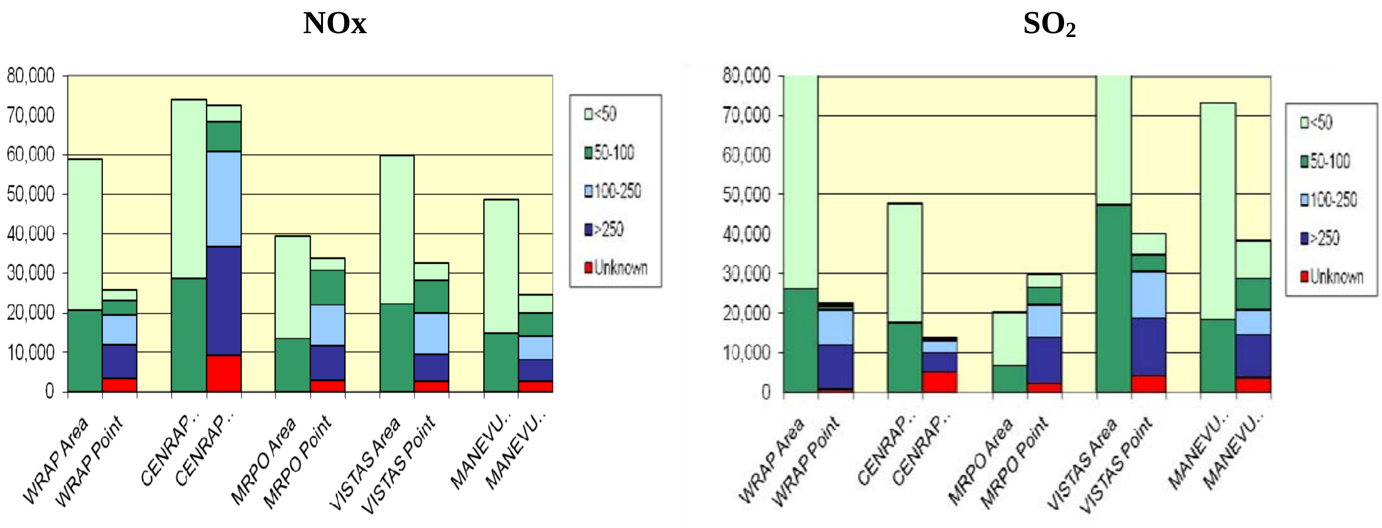


Figure 4. Regional Emission Reductions (tons/yr) from Oil- and Natural Gas-Fired Boilers by Boiler Size in MMBtu/hr



V. Cost Estimates

Cost estimates in this report are based on a methodology similar EPA's methodology provided in the EPA document "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers" (ACT). The Workgroup prepared preliminary cost estimates using spreadsheets originally developed by a contractor, MACTEC, with some revisions to correct operational problems and update them with new flue gas flow rate values and new cost factors based on input from the OTC/LADCO Control Cost Subgroup. Specifically, the cost effectiveness estimates in Tables 4 and 5 and Figure 5 are based on the following references:

- The "ACT" document from EPA entitled "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers", EPA-453/R-94-022, March 1994, which contains cost information for NOx control on consistent basis (size of boilers, capacity factor, economic parameters).
- The Air Pollution Control Technology Fact Sheets from EPA (EPA-452/F-03-031, EPA-452/F-03-032, and EPA-452/F-03-034), which contain additional information.
- The MACTEC Midwest RPO BART Engineering Analysis, March 30, 2005.

- Revised preliminary estimates using corrected MACTEC spreadsheets based on the EPA methodology provided in ACT. The original MACTEC spreadsheets have been revised to correct operational problems and updated with new flue gas flow rate values and new cost factors based on input from the Control Cost Subgroup.
- Miscellaneous papers and studies with cost information; however, the costs reported are in some cases incomplete and cannot be compared with other information on the same basis.
- EPA references where an escalation of 3% per year was used to convert the costs from 1994$ or 1999$ to 2008$. The escalation factor used was 1.604706. An alternative method, based on the use of the U.S. Bureau of Labor's calculations, was used for converting dollars in the MACTEC spreadsheets from 2004$ to 2008$. The U.S. Bureau of Labor's calculations are based on the Consumer Price Index (see http://www.bls.gov/cpi/).

Appendix A shows two examples of the results of the updated cost effort by the Control Cost Subgroup. This effort strived to take into account all foreseeable costs that a source may incur (capital, operating, maintenance, labor, insurance, etc.) to arrive at realistic cost-effectiveness numbers. The first two-page example supplies the many cost factors that go into calculating the cost-effectiveness of installing a single low NOx burner on a 250 MMBtu/hour gas-fired boiler; the second example is for installing a wet flue gas desulfurization (Wet FGD) system on a 250 MMBtu/hour coal-fired boiler. Please note that these spreadsheets are available to input real-world costs, and the hope is that stakeholders will not only comment on the cost assumptions but take advantage of this unique tool to internally evaluate control options.

The types of control equipment available for stakeholder cost analysis include:

- Low NOx Burners (LNB)
- Low NOx Burners plus Flue Gas Recirculation (LNB+FGR)
- Low NOx Burners plus Selective Non-Catalytic Reduction (LNB+SNCR)
- Selective Non-Catalytic Reduction (SNCR)
- Selective Catalytic Reduction (SCR)

- Dry Flue Gas Desulfurization (Dry FGD) - This cost analysis for Dry FGD focused on spray dryer absorption systems which spray lime slurry into an absorption tower where SO_2 is absorbed by the slurry, forming calcium sulfite/calcium sulfate. These dry solids are carried out of the tower and collected by a fabric filter.
- Wet Flue Gas Desulfurization (Wet FGD) - There are several different versions of Wet FGD systems. The choice of Wet FGD system may be influenced by the sulfur content of the fuel (e.g., limestone forced oxidation systems are generally used when firing high sulfur coal while magnesium enhanced lime systems may be used for low and high sulfur coals). In this cost analysis the Wet FGD system used lime as the base in the scrubbing liquor. Other Wet FGD systems use caustic (NaOH) and limestone.

Table 4. Cost Effectiveness for NOx Control Technology Options
(Using the OTC/LADCO 2008 Version of the MACTEC spreadsheets)

Pollutant: NOx		**Cost Effectiveness ($/ton removed) 2008$***			
Control Technology	**Fuel Type**	**Boiler Size**			
		50 MMBTU/hr	**100 MMBTU/hr**	**250 MMBTU/hr**	**750 MMBTU/hr**
LNB - Gas	Gas	$10,900 - $43,600	$5,460 - $21,800	$2,190 - $8,720	$728 - $2,910**
LNB - Dist. Oil	Distillate Oil	$10,900 - $43,600	$5,460 - $21,800	$2,190 - $8,720	$728 - $2,910**
LNB - Res. Oil	Residual Oil	$5,460 - $21,800	$2,730 - $10,900	$1,090 - $4,360	$364 - $1,450**
LNB - Coal	Coal	$3,210 - $12,460	$1,560 - $6,230	$624 - $2,490	$208 - $831**
SNCR – Coal (Wall-fired)	Coal	$7,210 - $9,930	$4,260 - $5,620	$2,480 - $3,030	$1,690 – $1,880
SCR – Coal (Wall-Fired)	Coal	$6,500 - $22,840	$3,430 - $11,600	$1,590 - $4,860	$770 - $1,860

*All costs shown are in 2008$ for a 66% capacity factor at 8760 hours/year.
** Low NOx Burner (LNB) cost estimates are for a single burner.

Table 5. Cost Effectiveness for SO_2 Control Technology Options
(Using the OTC/LADCO 2008 Version of the MACTEC spreadsheets)

Pollutant: SO_2		Cost Effectiveness ($/ton removed) 2008$ (1)		
Control Technology	Fuel Type	Boiler Size		
		100 MMBTU/hr	250 MMBTU/hr	750 MMBTU/hr
Low S Dist. Oil (2)	Distillate Oil	$1,200 - $2,000	$1,200 - $2,000	
Low S Res. Oil (3)	Residual Oil	$1,900 - $3,800	$1,900 - $3,800	$1,900 - $3,800
Dry Sorbent Injection – Coal (4)	Coal			
Dry FGD - Coal	Coal	$1,590 - $7,690	$1,480 - $4,010	$1,420 - $2,380
Wet FGD - Coal	Coal	$1,650 - $7,510	$1,400 - $3,830	$1,290 - $2,220

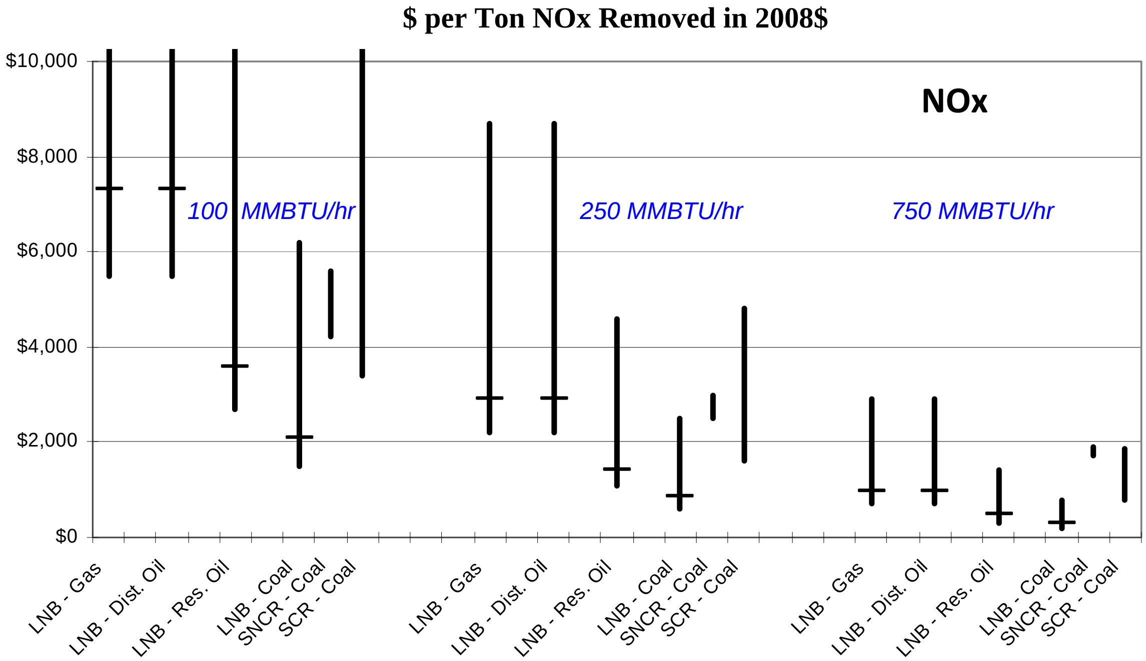
(1) All costs shown are in 2008$ for a 66% capacity factor at 8760 hour/year.

(2) The estimated price differential between distillate oil at 0.30% S and low sulfur distillate oil at 0.05%S used in these cost estimates ranged from 2.1 to 3.5 cents per gallon. Cost effectiveness not estimated for Low Sulfur Distillate Oil for the 750 MMBTU/hr boiler size because boilers of this size usually burn residual oil.

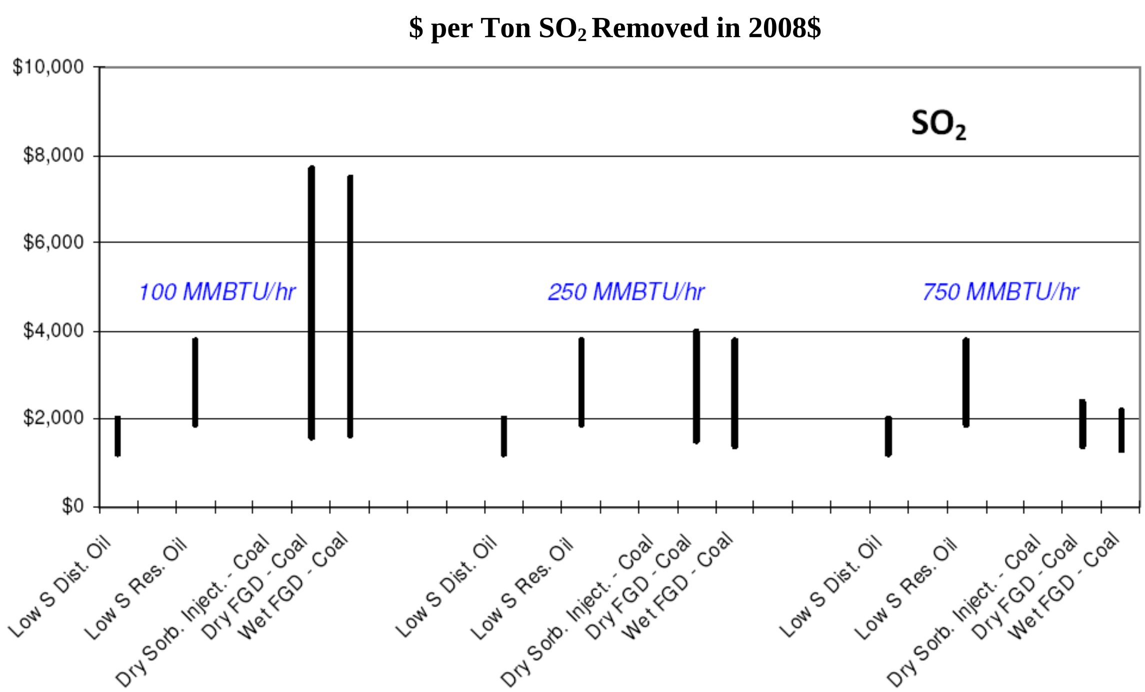
(3) The estimated price differential between residual oil at 1.0% S and low sulfur residual oil at 0.5%S used in these cost estimates ranged from 7.5 to 15.0 cents per gallon.

(4) Control costs ($/ton removed) for dry sorbent injection were not calculated due to the lack of detailed cost data.

Figure 5. NOx (top) and SO_2 (bottom) Cost Effectiveness Estimates



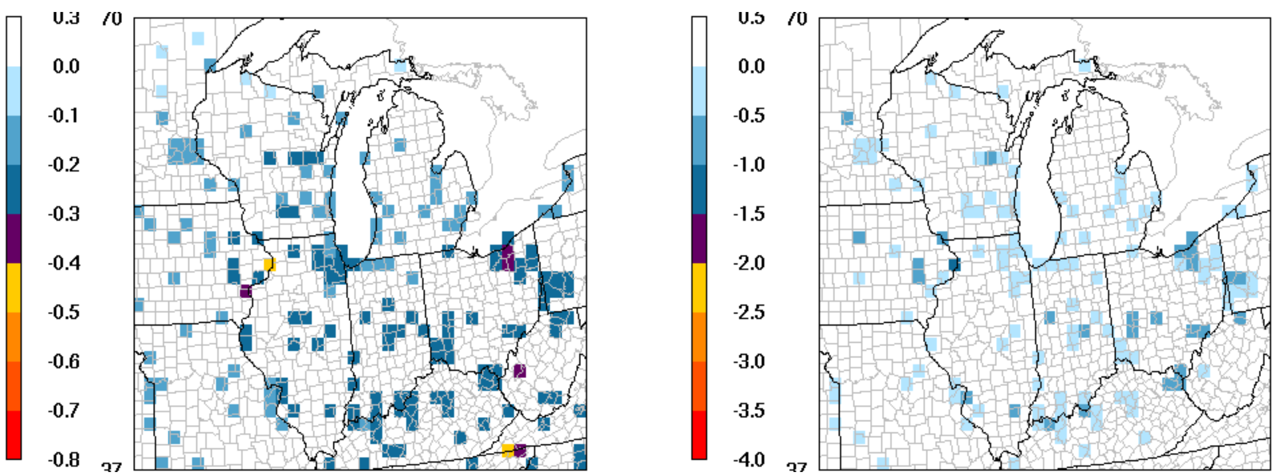
Note - The horizontal bars (—) in the figure shown above represent the cost effectiveness estimates for the medium capital cost cases and not the average of the cost effectiveness ranges



VI. <u>Air Quality Impacts</u>

LADCO performed a modeling analysis for the Midwest states to assess the air quality impacts of these emission reductions. Figure 6 below shows the change in annual and daily $PM_{2.5}$ concentrations by 2018. On average, annual $PM_{2.5}$ concentrations improved about 0.2 micrograms per cubic meter (ug/m^3) and daily $PM_{2.5}$ concentrations improved about 0.4 ug/m^3. In urban nonattainment areas, annual $PM_{2.5}$ concentrations improved about 0.3 ug/m^3 and daily $PM_{2.5}$ concentrations improved about 1 ug/m^3. Visibility levels for 2018 also improved about 0.2-0.3 deciviews:

Figure 6. Change in $PM_{2.5}$ Concentrations in 2018 Due to ICI Emission Limitations (ug/m^3)

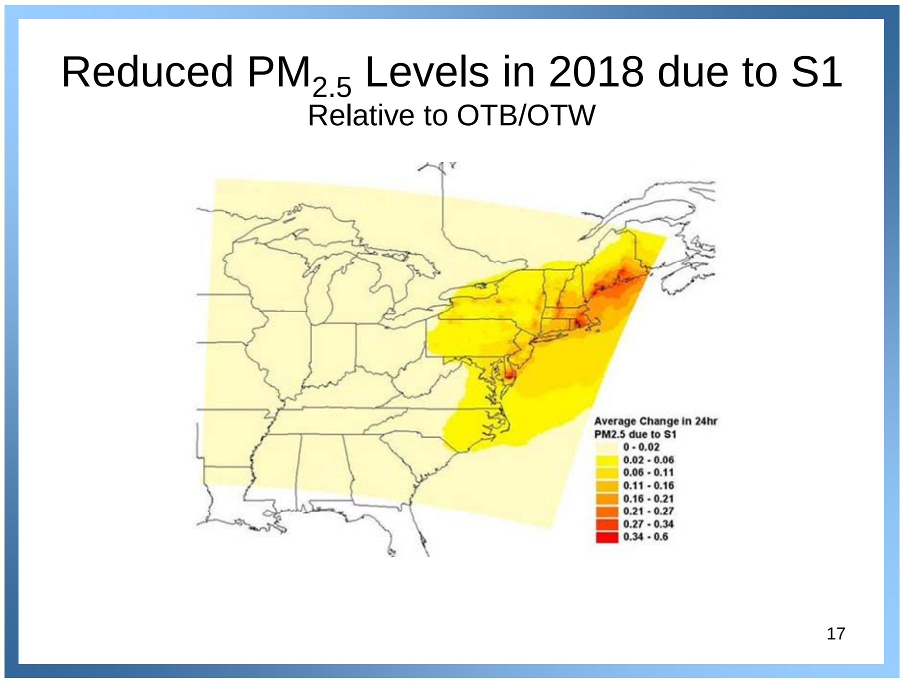


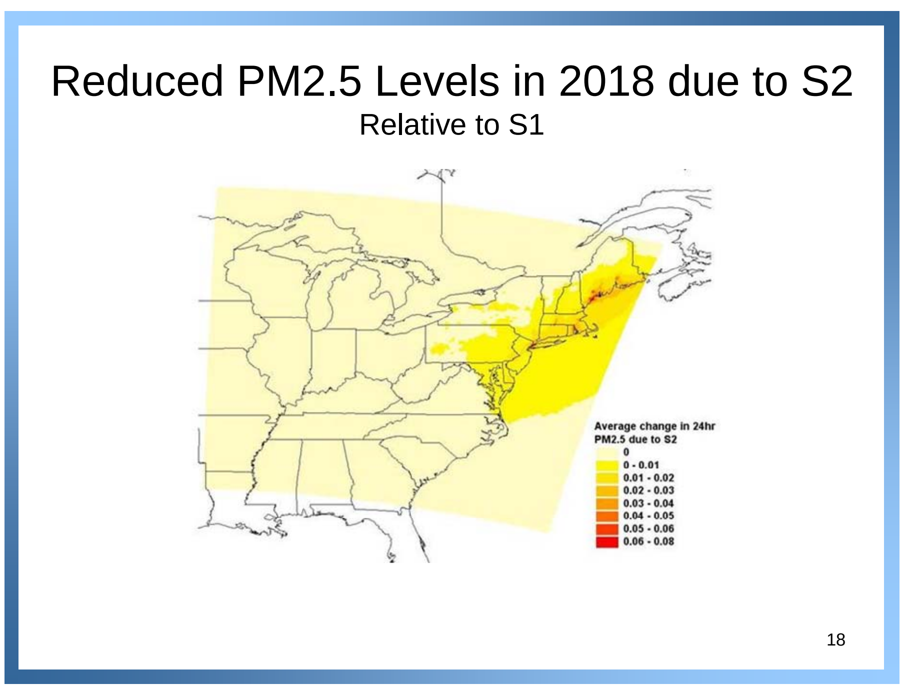
Annual **Daily**

A MANE-VU modeling analysis for the Northeast states was performed to assess the air quality improvement due to the MANE-VU Low-Sulfur Fuel Oil Initiative, a control measure planned across the MANE-VU region for meeting regional haze reasonable progress goals in 2018. Figure 7 below shows the change in daily $PM_{2.5}$ concentrations by 2018 due to the low-sulfur strategy <u>only</u>. At many locations on the Eastern seaboard, improvements as high as 0.6 ug/m^3 are expected from the S1 strategy, which reduces the sulfur content of #2 distillate to 500 parts per million (ppm) and #6 residual oil between 3000-5000 ppm. Both fuels are used widely in the ICI sector in the Northeast, although #2 is also extensively used for residential heating.

The second chart in Figure 7 shows the incremental improvement in air quality from the S2 strategy which further reduces the sulfur content of #2 distillate across the MANE-VU region from 500 ppm to 15 ppm by 2018.

Figure 7. MANE-VU Regional Modeling Results for Fuel Oil Strategies (Average Change in 24-hour $PM_{2.5}$ in $\mu g/m^3$)





VII. Background Documents

This evaluation relied on several previous studies. These studies provided valuable information on control options and cost effectiveness estimates for ICI boilers. A summary of the key findings or recommendations from these studies is provided below.

CCAP Report (2004): As part of the Air Quality Management Work Group, the Center for Clean Air Policy (CCAP) evaluated emissions from ICI boilers as a potential area for federal action. Based on a number of factors, such as emissions inventories, options for emissions controls, engineering and financing factors, and statutory authority, CCAP "believes a compelling case can be made to support regulation of this sector".

CAAAC Report (2005): In June 2004, the Clean Air Act Advisory Committee (CAAAC) formed the Air Quality Management Work Group, which was tasked with assessing the recommendations made by the National Research Council in its 2004 report, "Air Quality Management in the United States". In January 2005, the Work Group submitted its report to the CAAAC. The report included several recommendations, including expanding national and multi-state control strategies. For ICI boilers, the Work Group recommended that EPA: (1) complete a review of the contributions from this category and the technical and economic feasibility of further controls, and then (2) initiate development of a regional or national emissions control regulation for the category. The recommendation included an examination of the benefits (e.g., preliminary data indicate cost effectiveness values less than those deemed to be "highly cost effective" by EPA under CAIR), feasibility, timing, and resources. The Work Group identified this as a high priority recommendation.

MACTEC reports for MRPO (2005 & 2006): To support planning efforts by the Midwest Regional Planning Organization (MRPO), MACTEC prepared two reports. The first report was an evaluation of best available retrofit technology (BART) for ICI boilers (MACTEC, 2005). The report includes a review of available control technologies, an engineering analysis conducted in accordance with EPA's BART guidance (i.e., identification of available retrofit control options, identification of any existing control equipment at the source, estimation of control costs, assessment of remaining useful life of the source, and examination of energy and non-air quality environmental impacts of control options). For an initial list of 25 BART-eligible boilers in the Midwest RPO, MACTEC offered unit-specific recommendations on BART, ranging from ultra-low NOx burners to selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR) for NOx and flue gas desulfurization for SO_2. The second report identified candidate control measures for ICI boilers, as part of a series of White Papers (MACTEC, 2006). The White Papers include a description of the source category, brief regulatory history, discussion of candidate control measures, expected emission reductions, cost effectiveness, timing for implementation, and rule development issues. For ICI boilers, three candidate control measures were identified: ICI1 (60% NOx reduction, 40% SO_2 reduction for boilers > 100 MMBTU/hour), ICI2 (source-specific control requirements for boilers subject to BART, assumed to be an 80% NOx reduction [based on ultra-low NOx burner or SCR technology], 90% SO_2 reduction [based on FGD system]); and ICI3 (assumed BART reductions for all boilers > 100 MMBTU/hr).

MACTEC Report for OTC (2006): In 2006 MACTEC compiled a report in support of the OTC recommendations for state implementation plans to address the ozone NAAQS. As part of this report MACTEC examined reductions from ICI boilers that would occur based on the limits in OTC Resolution 06-02. The report contains control cost and emission reductions estimates. There is also an appendix that describes OTC state rules aimed a reducing emissions for ICI boilers. The report is available at www.otcair.org.

NESCAUM BART Report (2007): The Northeast States for Coordinated Air Use Management prepared a report for the Mid-Atlantic Northeast Visibility Union (MANE-VU) outlining the five-factor BART-determination process for BART-eligible source sectors in the MANE-VU region. Many of the non-EGU BART-eligible source industries overlap with the ICI boiler sector. The report summarizes control equipment options and their cost-effectiveness in a manner similar to the MACTEC Report for the MRPO described above.

<u>NESCAUM Report (2008)</u>: The Northeast States for Coordinated Air Use Management (NESCAUM), with contractor assistance, evaluated the viability of technologies for controlling emissions of NOx, SO_2, and PM from ICI boilers. For each pollutant, the report provides a description of available control technologies, discussion of the applicability of these technologies to ICI boilers, available cost estimates, and an assessment of control technologies on overall facility efficiency. Air pollution control equipment costs are estimated with The Coal Utility Environmental Cost (CUECost) model. The report found that: (1) ICI boilers are a significant source of NOx, SO_2, and PM emissions, which contribute to the formation of ozone, $PM_{2.5}$, and regional haze, and to ecosystem acidification; (2) ICI boilers are relatively uncontrolled compared to EGU boilers and offer the potential for cost-effective emission reductions; and (3) proven control technologies for EGUs can be scaled-down for use by ICI boilers, although careful analysis must be given to boiler size, fuel type/quality, duty-cycle, and design characteristics. The report offered no recommendation on specific control requirements, but rather stated that "regulators will need to determine the level of emission reductions needed from this sector in order to inform the appropriate choice of controls."

<u>Illinois Report (2008)</u>: The Illinois Environmental Protection Agency, with contractor assistance, prepared a technical support document for their state rulemaking on reasonably available control technology (RACT) for NOx. The document addresses seven source categories, including industrial and electrical generating unit boilers, and provides a description of each source category, the mechanism of NOx formation, the technical feasibility of controls, the cost effectiveness of controls, the existing and proposed regulations and the sources affected by the regulations (e.g., in the case of ICI boilers, units > 100 MMBTU/hour are covered).

Finally, it should be noted that many states in the Northeast and Midwest have adopted state rules for some ICI categories to control emissions of NOx or SO_2 from certain categories of ICI boilers. These existing state rules were taken into account in evaluating control options for ICI boilers. Links to state rules are provided in Appendix B.

VIII. References

Air Quality Management Work Group, "Recommendations to the Clean Air Act Advisory Committee, Phase I and Next Steps", January 2005.

Andover Technology Partners and the Illinois Environmental Protection Agency, "Technical Support Document for Control of Nitrogen Oxide Emissions from Industrial Boilers and Electrical Generating Unit Boilers, Process Heaters, Cement Kilns, Lime Kilns, Reheat, Annealing, and Galvanizing Furnaces used at Iron and Steel Plants, Glass Melting Furnaces, and Aluminum Melting Furnaces", AQPSTR 07-02, March 2008.

Center for Clean Air Policy, "Identification of Potential Areas of Further Federal Actions: Industrial, Commercial and Institutional Boilers", September 30, 2004.

MACTEC Inc., "Midwest Regional Planning Organization Boiler Best Available Retrofit Technology (BART) Engineering Analysis", March 30, 2005.

MACTEC Inc., "Interim White Paper: Midwest RPO Candidate Control Measures, Industrial, Commercial, and Institutional (ICI) Boilers", March 6, 2006.

Northeast States for Coordinated Air Use Management (NESCAUM), "Applicability and Feasibility of NOx, SO_2, and PM Emissions Control Technologies for Industrial, Commercial, and Institutional (ICI) Boilers", November 2008.

Ozone Transport Commission, OTC Addendum to Resolution 06-02 adopted by the Ozone Transport Commission, November 15, 2006.

U.S. Environmental Protection Agency, "Alternative Control Techniques Document – NOx Emissions from Industrial/Commercial/Institutional (ICI) Boilers", EPA-453/R-94-022, March 1994.

U.S. Environmental Protection Agency, "Air Pollution Control Technology Fact Sheets", EPA-452/F-03-031, EPA-452/F-03-032, EPA-452/F-03-034.

Appendix A
Control Cost Examples

CAPITAL COSTS			Boiler Size (MMBtu/hr):	250	250	250
Direct Capital Costs			Capital Cost Factor:	Low	Medium	High
Purchased Equipment						
Control device (A)			A = cost per MMBtu/hr X MMBtu/hr of the unit	$81,263	$210,000	$1,195,653
Instrumentation	10%	of control device cost (A)	= 10% X A	$8,126	$21,000	$119,565
Sales taxes	6.0%	of control device cost (A)	= 6% X A	$4,876	$12,600	$71,739
Freight	5%	of control device cost (A)	= 5% X A	$4,063	$10,500	$59,783
Auxiliary equipment (not incl. In CD cost)	-	of control device cost (A)				
Purchased Equipment Total (B)	21%		B = control device + instrumentation + sales taxes + freight	$98,328	$254,100	$1,446,740
Installation						
Foundations & supports	4%	of purchased equip cost (B)	= 4% X B	$3,933	$10,164	$57,870
Handling & erection	50%	of purchased equip cost (B)	= 20% X B	$19,666	$50,820	$289,348
Electrical	8%	of purchased equip cost (B)	= 4% X B	$3,933	$10,164	$57,870
Piping	1%	of purchased equip cost (B)	= 1% X B	$983	$2,541	$14,467
Insulation	7%	of purchased equip cost (B)	= 7% X B	$6,883	$17,787	$101,272
Painting	4%	of purchased equip cost (B)	= 4% X B	$3,933	$10,164	$57,870
Expenses not covered by items listed above	0%	of purchased equip cost (B)				
Site Preparation, as required		site-specific				
Buildings, as required		site-specific				
Installation Total	74%		= foundations & supports + handling & erection + electrical + piping + insullation + painting = 40% x B	$39,331	$101,640	$578,696
Total Direct Capital Cost			= Installation Total + Purchased Equipment Total (B)	$137,660	$355,740	$2,025,436
Indirect Capital Costs						
Engineering, supervision	10%	of purchased equip cost (B)	= 10% X B	$9,833	$25,410	$144,674
Construction, field expenses	20%	of purchased equip cost (B)	= 10% X B	$9,833	$25,410	$144,674
Construction fee	10%	of purchased equip cost (B)	= 10% X B	$9,833	$25,410	$144,674
Startup	1%	of purchased equip cost (B)	= 10% X B	$9,833	$25,410	$144,674
Tests	1%	of purchased equip cost (B)	= 1% X B	$983	$2,541	$14,467
Contingencies	3%	of purchased equip cost (B)	= 20% X B	$19,666	$50,820	$289,348
Total Indirect Capital Costs	45%		= engineering, supervision + construction, field expenses + construction fee + startup + tests + contingencies	$59,980	$155,001	$882,511
Total Capital Investment			= Total Direct Capital Cost + Total Indirect Capital Costs	$197,640	$510,741	$2,907,948
Replacement parts cost & installation labor	0	capital recovery costs, equipment life 20 years, interest rate 7%	= Total Capital Investment - Installation Cost			
Total Annualized Capital Costs			= Replacement parts cost & installation labor X CRF (CRF=0.1133)	$22,393	$57,867	$329,470
OPERATING COSTS						
Direct Operating Costs						
Operating labor	25.38	$/hr, 2.0 hr/8 hr shift, 8760 hr/yr, 66.0% of capacity	= $/hr X 2 hr/8 hr shift X hours/year X utilization	$36,685	$36,685	$36,685
Supervisor	15%	of operating labor costs	= 15% X operating labor	$5,503	$5,503	$5,503
Maintenance labor	17.77	$/hr, 1.0 hr/8 hr shift, 8760 hr/yr, 66.0% of capacity	= $/hr X 1 hr/8 hr shift X hours/year X utilization	$12,840	$12,840	$12,840
Maintenance materials	100%	of maintenance labor costs	= 100% X maintenance labor	$12,840	$12,840	$12,840
Utilities, reagents, waste management & replacements				$0	$0	$0
Electricity		NA		$0	$0	$0
Natural gas (fuel)		NA		$0	$0	$0
Water		NA		$0	$0	$0
Compressed air		NA		$0	$0	$0
Reagent #1(caustic)		NA		$0	$0	$0
Reagent #2		NA		$0	$0	$0
Solid waste disposal		NA		$0	$0	$0
Hazardous waste disposal		NA		$0	$0	$0
Wastewater treatment		NA		$0	$0	$0
Catalyst		NA		$0	$0	$0
Replacement parts		NA		$0	$0	$0
Total Annual Direct Operating Costs			= operating labor + supervisor + maintenance labor + maintenance materials	$67,868	$67,868	$67,868
Indirect Operating Costs						
Overhead	60%	of oper, maint & supervisor labor + maint materials costs	= 60% X Direct Operating Costs	$40,721	$40,721	$40,721
Property tax	1%	of total capital costs (TCI)	= 1% X Total Capital Investment	$1,976	$5,107	$29,079
Insurance	1%	of total capital costs (TCI)	= 1% X Total Capital Investment	$1,976	$5,107	$29,079
Administration	2%	of total capital costs (TCI)	= 2% X Total Capital Investment	$3,953	$10,215	$58,159
Total Indirect Operating Costs		sum of indirect operating costs + capital recovery cost	= overhead + property tax + insurance + administration + Total Annualized Capital Costs	$71,019	$119,017	$486,509
TOTAL ANNUAL COST (Annualized Capital Cost + Operating Cost)			= Total Indirect Operating Costs + Total Annual Direct Operating Costs	$138,887	$186,885	$554,377
Pollutants removed (tons/yr)			= tons/yr emitted w/o controls X % removal efficiency	72	72	72
Cost per Ton of NOx Removed ($2004)			= Total Annual Cost ÷ Pollutants Removed (tons/yr)	$1,922	$2,586	$7,671

Note: Values in 2nd column are typical (program default) values. All entries in red are selected values which differ from program default values.

Capital Recover Factors				Input values			Comments/Notes
Primary Installation				Relevant calculated values			
Interest rate (IR)		7.5%					
Equipment life (EL)		15	years				
CRF		0.1133					CRF =[IR X (1 + IR) ^ EL] / [(1 + IR) ^ EL - 1]
Catalyst Replacement Cost							
Catalyst life (CL)		4	years				
CRF		0.2986					
Catalyst cost per unit		650	$/ft³				
Amount Required		0	ft³				
Catalyst cost		0					Cost adjusted for freight & sales tax
Installation labor		0					Assume labor = 15% of catalyst cost
Total Installed Cost		0					(basis: labor for baghouse replacement)
Annualized Cost		0					
Replacement Parts & Equipment							
Equipment life		2	years				
CRF		0.5569					
Replacement part cost per unit		33.72	$ each				
Amount required		0	number				
Total replacement parts cost		0					Cost adjusted for freight & sales tax
Installation labor		0					10 min per bag (13 hr total) labor at $29.65/hr
Total Installed Cost		0					
Annualized Cost		0					
Total Cost Replacement Parts & Catalyst		0					= (replacement parts cost & installation labor) X CRF
Design Flow	48,790	dscfm	59,336	scfm			scfm = dscfm X [1 / (1 - % moisture)]
	725	temp F					
	17.774%	% moisture					
	130,938	acfm					acfm = scfm X (temp F + 460) / (77 + 460)

Operating Cost Calculations				Annual hours of operation:		8,760	Comments/Notes
				Utilization rate:		66%	(See additional notes at bottom)
Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	
Labor and Maintenance							
Operator labor	25.38	hr	2	hr/8 hr shift	1,445	36,685	$/hr, 2.0 hr/8 hr shift, 8760 hr/yr, 66.0% of capacity
Supervisor labor	NA				NA	NA	15% of operator costs
Maintenance Labor	17.77	hr	1	hr/8 hr shift	723	12,840	$/Hr, 1.0 hr/8 hr shift, 8760 hr/yr, 66.0% of capacity
Maintenance materials	NA		NA		NA	NA	
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.046	kW-hr	0.0	kW-hr	0	0	$/kW-hr, 0 kW-hr, 8760 hr/yr, 66.0% of capacity
Natural gas	4.24	Mft³	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 66.0% of capacity
Water	0.2	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 66.0% of capacity
Compressed air	0	Mscf	0	Mscfm	0	0	$/Mscf, 0.0 Mscfm, 8760 hr/yr, 66.0% of capacity
Reagent #1(caustic)	300	ton	0	lb-mole/hr	0	0	$/ton, 0.0 lb-mole/hr, 8760 hr/yr, ammonia
Reagent #2	300	ton	0	lb-mole/hr	0	0	$/ton, 0.0 lb-mole/hr, 8760 hr/yr, 50 wt % urea solution
Solid waste disposal	0	ton	0.000	ton/hr	0	0	$/ton, 0.200 lb/MMBtu, 8760 hr/yr
Hazardous waste disposal	273	ton	0.000	ton/hr	0	0	$/ton, 0.200 lb/MMBtu, 8760 hr/yr
Wastewater treatment	1.5	Mgal	0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 66.0% of capacity
Catalyst	650	ft³	0	ft³	4 yr life	0	$/ft3, 0.0 ft3, 4 yr life, 8760 hr/yr, 66.0% of capacity
Replacement parts	33.72	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 66.0% of capacity
					*Annual use rate is in same units of measurement as the unit cost factor.		

Emission Control Rate Calculation								Comments/Notes
	Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emission Rate	Unit of Measure	
Uncontrolled emissions	0.200	lb/MMBtu	250	MMBtu/hr	NA	145	ton/yr	Uncontrolled emissions rate = emission factor X flow rate X annual hours of operation X utilization rate / 2000
Controlled emissions:								Controlled Emissions Rate = Uncontrolled emission rate X
Performance guarantee	NA		NA		50%	72	ton/yr	(1 - control efficiency)
Emission reductions	NA		NA		NA	72	ton/yr	Emission reductions = uncontrolled emission rate - controlled emission rate

Blower Data	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW		
	0	5	0.55	0.9	0.0		OAQPS Cost Cont Manual 5th ed - Eq 3.37

Note: All entries in red are selected values which differ from program default values.

Notes for labor and maintenance cost calculations:
Operating labor annual use = # hr / 8 hr shift X annual hours of operation X utilization rate
Operating labor annual cost = operating labor unit cost X operating labor annual use
Maintanance labor annual use = # hr / 8 hr shift X annual hours of operation X utilization rate
Maintanance labor annual cost = maintenance labor unit cost X maintenance labor annual use

			Boiler Size (MMBtu/hr):	250	250	250	250	250
			Boiler Type:	Wall-F Coal	Wall-F Coal	Wall-F Coal	Wall-F Coal	Pulv Coal
			Fuel Sulfur Content:	2.5%	2.5%	2.5%	2.5%	2.5%
			SO_2 Removal Efficiency:	85%	85%	95%	95%	90%
CAPITAL COSTS								
Direct Capital Costs			Capital Cost Factor:	Low	High	Low	High	High
Purchased Equipment								
Purchased equipment costs - absorber + packing + auxillary equipment, EC			A = cost per MMBtu/hr X MMBtu/hr	$406,298	$15,243,451	$406,298	$15,243,451	$15,243,451
Instrumentation	10%	of control device cost (A)	= 10% X A	$40,630	$1,524,345	$40,630	$1,524,345	$1,524,345
Sales taxes	6.0%	of control device cost (A)	= 6% X A	$24,378	$914,607	$24,378	$914,607	$914,607
Freight	5%	of control device cost (A)	= 5% X A	$20,315	$762,173	$20,315	$762,173	$762,173
Purchased Equipment Total (B)	21%		B = control device + instrum + sales taxes + freight	$491,621	$18,444,576	$491,621	$18,444,576	$18,444,576
Installation								
Foundations & supports	12%	of purchased equip cost (B)	= 4% X B	$19,665	$737,783	$19,665	$737,783	$2,213,349
Handling & erection	40%	of purchased equip cost (B)	= 20% X B	$98,324	$3,688,915	$98,324	$3,688,915	$7,377,830
Electrical	1%	of purchased equip cost (B)	= 4% X B	$19,665	$737,783	$19,665	$737,783	$184,446
Piping	30%	of purchased equip cost (B)	= 1% X B	$4,916	$184,446	$4,916	$184,446	$5,533,373
Insulation	1%	of purchased equip cost (B)	= 7% X B	$34,413	$1,291,120	$34,413	$1,291,120	$184,446
Painting	1%	of purchased equip cost (B)	= 4% X B	$19,665	$737,783	$19,665	$737,783	$184,446
Installation Total	85%		= foundations & supports + handling & erection + electrical + piping + insulation + painting = 40% X B	$196,648	$7,377,830	$196,648	$7,377,830	$15,677,889
Site preparation, as required		site-specific						
Buildings, as required		site-specific						
Total Direct Capital Cost			= installation total + purchased equipment total (B)	$688,269	$25,822,406	$688,269	$25,822,406	$34,122,465
Indirect Capital Costs								
Engineering, supervision	10%	of purchased equip cost (B)	= 20% X B	$98,324	$3,688,915	$98,324	$3,688,915	$1,844,458
Construction, field expenses	10%	of purchased equip cost (B)	= 20% X B	$98,324	$3,688,915	$98,324	$3,688,915	$1,844,458
Construction fee	10%	of purchased equip cost (B)	= 20% X B	$98,324	$3,688,915	$98,324	$3,688,915	$1,844,458
Start-up	1%	of purchased equip cost (B)	= 10% X B	$49,162	$1,844,458	$49,162	$1,844,458	$184,446
Performance test	1%	of purchased equip cost (B)	= 2% X B	$9,832	$368,892	$9,832	$368,892	$184,446
Contingencies	3%	of purchased equip cost (B)	= 20% X B	$98,324	$3,688,915	$98,324	$3,688,915	$553,337
Total Indirect Capital Costs	35%		= engineering, supervision + construction, field expenses + construction fee + startup + test + contingencies = 92%	$452,291	$16,969,010	$452,291	$16,969,010	$6,455,601
Total Capital Investment (TCI)			= Total Direct Capital Cost + Total Indirect Capital Costs	$1,140,560	$42,791,416	$1,140,560	$42,791,416	$40,578,067
OPERATING COSTS								
Direct Operating Costs								
Operating labor								
Operator	25.38	$/hr, 0.5 hr/8 hr shift, 8760 hr/yr, 66.0% of capacity	= $/hr X 0.5 hr/8 hr shift X hours/year X utilization	$9,171	$9,171	$9,171	$9,171	$11,421
Supervisor	15%	of operating labor costs	= 15% X operator cost	$1,376	$1,376	$1,376	$1,376	$1,713
Operating materials								
Reagent #1	NA	$/ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt % NaOH						
Reagent #2	304.57	$/ton, 245.9 lb/hr, 8760 hr/yr, 62 lb/lbmole, lime	caustic annual lime = unit cost X lime annual usage rate	$1,872,478	$1,872,478	$1,872,478	$1,872,478	$2,295,418
Water				$609	$609	$609	$609	$1,018
Compressed air				$87	$87	$87	$87	$108
Solid waste disposal				$163,517	$163,517	$163,517	$163,517	$273,342
Catalyst	NA							
Wastewater treatment	NA	$/Mgal, 0.0 gpm, 8760 hr/yr, 66.0% of capacity						
Maintenance								
Maintenance labor	17.77	1/2 hr per shift	= $/hr X 0.5 hr/8 hr shift X hours/year X utilization	$6,420	$6,420	$6,420	$6,420	$7,995
Maintenance materials	100%	of maintenance labor costs	= 100% X maintenance labor cost	$6,420	$6,420	$6,420	$6,420	$7,995
Electricity - fan, pump	0.05	$/kW-hr, 1,669 kW-hr, 8760 hr/yr, 66.0% of capacity	electricity annual cost = annual usage X unit cost	$72,142	$72,142	$72,142	$72,142	$476,256
Total Annual Direct Operating Costs			= operator + supervisor + reagent #2 + water + compr air + sw disposal + maint labor + maint materials + electricity	$2,132,220	$2,132,220	$2,132,220	$2,132,220	$3,075,266
Indirect Operating Costs								
Overhead	60%	of total labor and material costs	= 60% X (operator labor + supervisor labor + maintenance labor + maintenance materials)	$14,032	$14,032	$14,032	$14,032	$17,474
Administration	2%	of total capital costs (TCI)	= 2% X total capital investment	$22,811	$855,828	$22,811	$855,828	$811,561
Property tax	1%	of total capital costs (TCI)	= 1% X total capital investment	$11,406	$427,914	$11,406	$427,914	$405,781
Insurance	1%	of total capital costs (TCI)	= 1% X total capital investment	$11,406	$427,914	$11,406	$427,914	$405,781
Capital recovery	14.24%	for a 10-year equipment life and a 7% interest rate	= 11.33% X total capital investment	$129,225	$4,848,267	$129,225	$4,848,267	$5,778,317
Total Annual Indirect Operating Costs		Sum of indirect operating costs + capital recovery cost	= overhead + admin + property tax + insurance + capital recovery + Total Annual Direct Operating Costs	$2,321,100	$8,706,176	$2,321,100	$8,706,176	$10,494,180
TOTAL ANNUAL COST (Annualized Capital Cost + Operating Cost)			= Total Annual Direct Operating Costs + Total Annual Indirect Operating Costs	$4,453,320	$10,838,396	$4,453,320	$10,838,396	$13,569,446
Pollutant removed (tons/yr)			= tons/yr emitted w/o controls X % removal efficiency	3,071	3,071	3,433	3,433	3,987
Cost per Ton of SO2 Removed			= Total Annual Cost ÷ Pollutants Removed (tons/yr)	$1,450	$3,529	$1,297	$3,157	$3,404

Note: Values in 2nd column are typical (program default) values. All entries in red are selected values which differ from program default values.

Capital Recover Factors				Input values			Comments/Notes
Primary Installation				Relevant calculated values			
Interest rate (IR)		7.5%					
Equipment life EL)		15	years				
CRF		0.1133					CRF = [IR X (1 + IR) ^ EL] / [(1 + IR) ^ EL - 1]
Catalyst Replacement Cost							
Catalyst life		4	years				
CRF		0.2986					
Catalyst cost per unit		650	$/$ft^3$				
Amount required		0	ft^3				
Catalyst cost		0					Cost adjusted for freight & sales tax
Installation labor		0					Assume labor = 15% of catalyst cost
Total Installed Cost		0					(basis: labor for baghouse replacement)
Annualized Cost		0					
Replacement Parts & Equipment							
Equipment Life		2					
CRF		0.5569					
Replacement part cost per unit		33.72	$ each				
Amount required		0	number				
Total replacement parts cost		0					Cost adjusted for freight & sales tax
Installation labor		0					10 min per bag (13 hr total) labor at $29.65/hr
Total installed cost		0					
Annualized cost		0					
Total Cost Replacement Parts & Catalyst		0					= (replacement parts cost & installation labor) X CRF

Design Flow	68,623	dscfm	73142	scfm			scfm = dscfm X [1 / (1 - % moisture)]
	350	temp F					
	6.179%	% moisture					
	110,327	acfm					acfm = scfm X (temp F + 460) / (77 + 460)

Operating Cost Calculations				Annual hours of operation:		8,760	Comments/Notes
				Utilization Rate:		66.0%	(See additional notes on Sheet 2a)
Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	
Labor and Maintenance							
Operator labor	25.38	hr	0.5	hr/8 hr shift	361	9,171	$/hr, 0.5 hr/8 hr shift, 8760 hr/yr, 66.0% of capacity
Supervisor labor	15%	of operator			NA	1,376	15% of operator costs
Maintenance Labor	17.77	hr	0.5	hr/8 hr shift	361	6,420	$/hr, 0.5 hr/8 hr shift, 8760 hr/yr, 66.0% of capacity
Maintenance materials	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	265.9	kW-hr	1,537,555	72,142	$/kW-hr, 266 kW-hr, 8760 hr/yr, 66.0% of capacity
Natural gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 66.0% of capacity
Water	0.20	Mgal	8.6	gpm	3,000	609	$/Mgal, 8.6 gpm, 8760 hr/yr, 66.0% of capacity
Compressed air	0.25	Mscf	1	Mscfm	347	87	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 66.0% of capacity
Reagent #1(caustic)	280.00	ton	0.00	lb/hr	0	0	$/ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt % NaOH
Reagent #2	304.57	ton	1403.65	lb/hr	6,148	1,872,478	$/ton, 1,403.6 lb/hr, 8760 hr/yr, 62 lb/lbmole, lime
Solid waste disposal	25.38	ton	1.114	ton/hr	6,443	163,517	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Hazardous waste disposal	273	ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Wastewater treatment	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 66.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 66.0% of capacity
Replacement parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 66.0% of capacity
					*Annual use rate is in same units of measurement as the unit cost factor.		

Emission Control Rate Calculation								Comments/Notes
	Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emission Rate	Unit of Measure	
Uncontrolled Emissions	5.00	lb/MMBtu	250	MMBtu/hr	NA	3,613.50	T/yr	Uncontrolled Emissions Rate = Emission factor X flow rate
								X annual hours of operation X utilization rate / 2000
Controlled Emissions:								Controlled Emissions Rate = Uncontrolled emission rate X
Performance Guarantee	NA		NA		85%	542	T/yr	(1 - control efficiency)
Emission Reduction	NA		NA		NA	3071.5	T/yr	Emission Reduction = uncontrolled emission rate -
								controlled emission rate
								Basis: 8760 hr/yr at 66.0% of capacity

Technical Data							Comments/Notes
	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW		(See additional notes on Sheet 2a)
Blower	72,816	12	0.55	0.7	265.5		OAQPS Cost Cont Manual 6th ed - Eq 1.48
Pumps	Flow gpm	P ft H2O	Pump Eff	Motor Eff			
Circulation pump	10	125	0.8	0.7	0.4		OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O wastewater discharge	0.0	62.5	0.8	0.7	0.0		OAQPS Cost Cont Manual 6th ed - Eq 1.49
Caustic use	825.00	lb/hr SO2	2.50	lb NaOH/lb SO2	2062.50	lb/hr caustic	
Lime use	825.00	lb/hr SO2	1.7	lb lime/lb SO2	1403.65	lb/hr lime	
Water makeup rate / wastewater discharge = 20% of circulating water rate							
Utility use rate basis: 8760 hr/yr, 66.0% of capacity							
SO2 flow rate	825.00	lb/hr					
Reagent feed rate	1403.65	lb/hr					Equation 6-38 EPA/600/R-00/093

Reagent flow rate	9.50	gpm					Equation 6-39 EPA/600/R-00/093
Water use	8.65	gpm					

All entries in red are selected values which differ from program default values.

Notes for operating cost calculations:

Operator labor annual usage = usage rate / 8 X annual hours of operation X utilization rate
Operator annual cost = operator annual usage X cost per unit
Supervisor annual cost = 15% X operator annual cost
Maintenace labor annual usage = usage rate / 8 X annual hours of operation X utilization rate
Maintenance annual cost = maintenance labor annual usage X cost per unit
Electricity usage rate = pump kW + blower kW
Electricity annual usage = usage rate X annual hours of operation X rate of utilization
Electricity annual cost = annual usage X unit cost
Water annual usage = usage rate X 60 X annual usage / 1000 X utilization rate
Water annual cost = unit cost X water annual usage
Compressed air annual usage = compressed air usage rate X annual operating hours / 1000 X utilization rate
Compressed air annual cost = compressed air annual usage X unit cost
Lime annual usage = lime usage rate X (annual hours of operation / 2000)
Lime annual cost = lime annual usage X unit cost
Solid waste generation rate = (lb/hr SO2 controlled + lb/hr lime) / 2000
Solid waste generation annual rate = solid waste generation rate X annual operation hours X utilization rate
Solid waste disposal cost = solid waste generation annual rate X unit cost

Notes for technical data:

Blower kW = 0.000117 X acfm X delta pressure / (blower efficiency X motor efficiency)
Average listed range efficiency for blowers
Pump kW = 0.746 X 0.000252 X flow gpm X delta pressure / (pump efficiency X motor efficiency)
Highest efficiency from pump curves, Perry's 5th, p. 6-7
Highest efficiency from pump curves, Perry's 5th, p. 6-7
Uncontrolled SO2 lb/hr = uncontrolled emissions X (2000 / annual hours of operation)
Reagent feed rate = SO2 lb/hr X 1.75 X 56 / 64 + SO2 lb/hr X 1.75 X 56 / 64 X [(1-0.9) / 0.9]
Reagent flow rate =[(reagent feed rate X 74 / 56 + reagent feed rate X 74 / 56 X [(1-0.3) / 0.3]) / (8.34 X 1.3)] / 60
Water use = reagent flow rate X 1.3 X 8.34 X 0.7 / 8.34

(Sheet 3)

Capital Recover Factors				Input values			Comments/Notes
Primary Installation				Relevant calculated values			
Interest rate (IR)		7.5%					
Equipment life EL)		15	years				
CRF		0.1133					CRF = [IR X (1 + IR) ^ EL] / [(1 + IR) ^ EL - 1]
Catalyst Replacement Cost							
Catalyst life		4	years				
CRF		0.2986					
Catalyst cost per unit		650	$/ft^3				
Amount required		0	ft^3				
Catalyst cost		0					Cost adjusted for freight & sales tax
Installation labor		0					Assume labor = 15% of catalyst cost
Total Installed Cost		0					(basis: labor for baghouse replacement)
Annualized Cost		0					
Replacement Parts & Equipment							
Equipment Life		2					
CRF		0.5569					
Replacement part cost per unit		33.72	$ each				
Amount required		0	number				
Total replacement parts cost		0					Cost adjusted for freight & sales tax
Installation labor		0					10 min per bag (13 hr total) labor at $29.65/hr
Total installed cost		0					
Annualized cost		0					
Total Cost Replacement Parts & Catalyst		0					= (replacement parts cost & installation labor) X CRF

Design Flow	68,623	dscfm	73142	scfm			scfm = dscfm X [1 / (1 - % moisture)]
	350	temp F					
	6.179%	% moisture					
	110,327	acfm					acfm = scfm X (temp F + 460) / (77 + 460)

Operating Cost Calculations				Annual hours of operation:		8,760	Comments/Notes
					Utilization Rate:	66.0%	(See additional notes on Sheet 3a)
Item	Unit Cost $	Unit of Measure	Use Rate	Unit of Measure	Annual Use*	Annual Cost	
Labor and Maintenance							
Operator labor	25.38	hr	0.5	hr/8 hr shift	361	9,171	$/hr, 0.5 hr/8 hr shift, 8760 hr/yr, 66.0% of capacity
Supervisor labor	15%	of operator			NA	1,376	15% of operator costs
Maintenance Labor	17.77	hr	0.5	hr/8 hr shift	361	6,420	$/hr, 0.5 hr/8 hr shift, 8760 hr/yr, 66.0% of capacity
Maintenance materials	NA				NA	1%	of purchased equipment costs
Utilities, Reagents, Waste Management & Replacements							
Electricity	0.047	kW-hr	265.9	kW-hr	1,537,555	72,142	$/kW-hr, 266 kW-hr, 8760 hr/yr, 66.0% of capacity
Natural gas	4.24	Mft^3	0	scfm	0	0	$/Mft3, 0.0 scfm, 8760 hr/yr, 66.0% of capacity
Water	0.20	Mgal	8.6	gpm	3,000	609	$/Mgal, 8.6 gpm, 8760 hr/yr, 66.0% of capacity
Compressed air	0.25	Mscf	1	Mscfm	347	87	$/Mscf, 1.0 Mscfm, 8760 hr/yr, 66.0% of capacity
Reagent #1(caustic)	280.00	ton	0.00	lb/hr	0	0	$/ton, 0.0 lb/hr, 8760 hr/yr, 62 lb/lbmole, 50 wt % NaOH
Reagent #2	304.57	ton	1403.65	lb/hr	6,148	1,872,478	$/ton, 1,403.6 lb/hr, 8760 hr/yr, 62 lb/lbmole, lime
Solid waste disposal	25.38	ton	1.114	ton/hr	6,443	163,517	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Hazardous waste disposal	273	ton	0.000	ton/hr	0	0	$/ton, 4 gr/scf, 50 Mscfm, 8460 hr/yr
Wastewater treatment	1.52	Mgal	0.0	gpm	0	0	$/Mgal, 0.0 gpm, 8760 hr/yr, 66.0% of capacity
Catalyst	0	ft^3	0	ft^3	2 yr life	0	$/ft3, 0.0 ft3, 2 yr life, 8760 hr/yr, 66.0% of capacity
Replacement parts	0	bag	0	bags	2 yr life	0	$/bag, 0.0 bags, 2 yr life, 8760 hr/yr, 66.0% of capacity
					*Annual use rate is in same units of measurement as the unit cost factor.		

Emission Control Rate Calculation								Comments/Notes
	Emission Factor	Unit of Measure	Flow Rate	Unit of Measure	Control Eff. %	Emission Rate	Unit of Measure	
Uncontrolled Emissions	5.00	lb/MMBtu	250	MMBtu/hr	NA	3,613.50	T/yr	Uncontrolled Emissions Rate = Emission factor X flow rate X annual hours of operation X utilization rate / 2000
Controlled Emissions:								Controlled Emissions Rate = Uncontrolled emission rate X (1 - control efficiency)
Performance Guarantee	NA		NA		95%	181	T/yr	
Emission Reduction	NA		NA		NA	3432.8	T/yr	Emission Reduction = uncontrolled emission rate - controlled emission rate
								Basis: 8760 hr/yr at 66.0% of capacity

Technical Data							Comments/Notes
	Flow acfm	D P in H2O	Blower Eff	Motor Eff	kW		(See additional notes on Sheet 2a)
Blower	72,816	12	0.55	0.7	265.5		OAQPS Cost Cont Manual 6th ed - Eq 1.48
Pumps	Flow gpm	P ft H2O	Pump Eff	Motor Eff			
Circulation pump	10	125	0.8	0.7	0.4		OAQPS Cost Cont Manual 6th ed - Eq 1.49
H2O wastewater discharge	0.0	62.5	0.8	0.7	0.0		OAQPS Cost Cont Manual 6th ed - Eq 1.49
Caustic use	825.00	lb/hr SO2	2.50	lb NaOH/lb SO2	2062.50	lb/hr caustic	
Lime use	825.00	lb/hr SO2	1.7	lb lime/lb SO2	1403.65	lb/hr lime	
Water makeup rate / wastewater discharge = 20% of circulating water rate							
Utility use rate basis: 8760 hr/yr, 66.0% of capacity							
SO2 flow rate	825.00	lb/hr					

Reagent feed rate	1403.65	lb/hr					Equation 6-38 EPA/600/R-00/093
Reagent flow rate	9.50	gpm					Equation 6-39 EPA/600/R-00/093
Water use	8.65	gpm					

All entries in red are selected values which differ from program default values.

Notes for operating cost calculations:

Operator labor annual usage = usage rate / 8 X annual hours of operation X utilization rate
Operator annual cost = operator annual usage X cost per unit
Supervisor annual cost = 15% X operator annual cost
Maintenace labor annual usage = usage rate / 8 X annual hours of operation X utilization rate
Maintenance annual cost = maintenance labor annual usage X cost per unit
Electricity usage rate = pump kW + blower kW
Electricity annual usage = usage rate X annual hours of operation X rate of utilization

Electricity annual cost = annual usage X unit cost
Water annual usage = usage rate X 60 X annual usage / 1000 X utilization rate
Water annual cost = unit cost X water annual usage
Compressed air annual usage = compressed air usage rate X annual operating hours / 1000 X utilization rate
Compressed air annual cost = compressed air annual usage X unit cost
Lime annual usage = lime usage rate X (annual hours of operation / 2000)
Lime annual cost = lime annual usage X unit cost
Solid waste generation rate = (lb/hr SO2 controlled + lb/hr lime) / 2000
Solid waste generation annual rate = solid waste generation rate X annual operation hours X utilization rate
Solid waste disposal cost = solid waste generation annual rate X unit cost

Notes for technical data:

Blower kW = 0.000117 X acfm X delta pressure / (blower efficiency X motor efficiency)
Average listed range efficiency for blowers
Pump kW = 0.746 X 0.000252 X flow gpm X delta pressure / (pump efficiency X motor efficiency)
Highest efficiency from pump curves, Perry's 5th, p. 6-7
Highest efficiency from pump curves, Perry's 5th, p. 6-7
Uncontrolled SO2 lb/hr = uncontrolled emissions X (2000 / annual hours of operation)
Reagent feed rate = SO2 lb/hr X 1.75 X 56 / 64 + SO2 lb/hr X 1.75 X 56 / 64 X [(1-0.9) / 0.9]
Reagent flow rate =[(reagent feed rate X 74 / 56 + reagent feed rate X 74 / 56 X [(1-0.3) / 0.3]) / (8.34 X 1.3)] / 60
Water use = reagent flow rate X 1.3 X 8.34 X 0.7 / 8.34

Appendix B
Links to State Rules

The following links provide a link to each state's general air regulations or, in some case, to regulations specifically governing ICI Boiler s or NOx RACT.

Connecticut: http://www.ct.gov/dep/cwp/view.asp?a=2704&q=323512&depNav_GID=1511&depNav=|

Delaware: http://www.awm.delaware.gov/AQM/Pages/AirRegulations.aspx

Illinois: see pages 13326 and 13345
http://www.cyberdriveillinois.com/departments/index/register/register_volume33_issue39.pdf

Indiana: The boiler rules, both general and source-specific, are found in Articles 6, 6.5, 6.8, 7 and 10.
http://www.ai.org/legislative/iac/title326.html

Maryland: http://www.mde.state.md.us/Programs/AirPrograms/index.asp

Maine: http://www.maine.gov/dep/air/overview.htm

Massachusetts: http://www.mass.gov/dep/air/laws/regulati.htm

Michigan: http://www.michigan.gov/deq/0,1607,7-135-3310_4108---,00.html

New Hampshire: http://des.nh.gov/organization/divisions/air/regulations.htm

New Jersey: http://www.state.nj.us/dep/aqm/rules.html
http://www.state.nj.us/dep/aqm/Sub19.pdf

New York: http://www.dec.ny.gov/regs/2492.html

Ohio: The NOx RACT rules are found in OAC Chapter 110.
http://www.epa.ohio.gov/dapc/regs/3745_110.aspx

Pennsylvania: http://www.dep.state.pa.us/dep/deputate/airwaste/aq/regs/regs.htm

Rhode Island: http://www.dem.ri.gov/pubs/regs/index.htm#AirAir Pollution Control Regulation No. 8:
http://www.dem.ri.gov/pubs/regs/regs/air/air08_07.pdf
Air Pollution Control Regulation No. 13: http://www.dem.ri.gov/pubs/regs/regs/air/air13_07.pdf
Air Pollution Control Regulation No. 27: http://www.dem.ri.gov/pubs/regs/regs/air/air27_07.pdf

Vermont: http://www.anr.state.vt.us/air/htm/AirRegulations.htm

Virginia: http://www.deq.state.va.us/air/regulations/airregs.html

Washington, D.C.: http://ddoe.dc.gov/ddoe/cwp/view,a,1209,q,498697,ddoeNav_GID,1486,ddoeNav,|31375|31377|.asp

Wisconsin: NOx RACT (NR 428.20 - 25) and BART rules (NR 433)
http://www.legis.state.wi.us/rsb/code/nr/nr428.pdf
http://www.legis.state.wi.us/rsb/code/nr/nr433.pdf

OZONE TRANSPORT COMMISSION

Connecticut

Delaware

District of Columbia

Maine

Maryland

Massachusetts

New Hampshire

New Jersey

New York

Pennsylvania

Rhode Island

Vermont

Virginia

Anna Garcia
Executive Director

444 N. Capitol St. NW
Suite 638
Washington, DC 20001
(202) 508-3840
FAX (202) 508-3841
e-mail: ozone@otcair.org

RESOLUTION 10-01 OF THE OZONE TRANSPORT COMMISSION CALLING ON THE US ENVIRONMENTAL PROTECTION AGENCY TO ADOPT AND IMPLEMENT ADDITIONAL NATIONAL RULES TO REDUCE OZONE TRANSPORT AND PROTECT PUBLIC HEALTH

Whereas, the Ozone Transport Commission (OTC) was established under Sections 176A and 184 of the federal Clean Air Act (CAA) to ensure the development and implementation of strategies to reduce ground-level ozone to healthful levels; and,

Whereas, elevated levels of ozone have been shown to cause respiratory illnesses, exacerbate or trigger asthma related episodes, increase respiratory-related emergency room and hospital admissions and compromise the immune system leading to increased incidents of other respiratory illnesses, including pneumonia and bronchitis, and to cause premature death; and,

Whereas, implementation of local controls cannot in itself be successful due to the significant transport of ozone and ozone precursor emissions from outside nonattainment areas; and,

Whereas, on March 12, 2008 EPA revised the ozone 8-hour standard of 0.08 parts per million (ppm) to 0.075 ppm and on January 19, 2010 EPA proposed to reconsider that standard and strengthen it to between 0.060 and 0.070 ppm; and,

Whereas, EPA analysis indicated widespread nonattainment across the nation of the revised standard levels under consideration; and,

Whereas, the recent modeling work conducted for the state collaborative (a joint effort of the OTC and the Lake Michigan Air Directors Consortium (LADCO)) and the OTC Conceptual Model show that a program of multi-sector emission reductions is necessary to reduce significant contributions from the transport of air pollutants across state boundaries even for the current ozone standard; and,

Whereas, such reductions will be even more critical for areas to achieve the new NAAQS for ozone and particulate matter, and to achieve reductions in other pollutants that contribute to regional haze; and,

Whereas, this work further confirms the need for tighter controls for the power, mobile and area source sectors; and,

Whereas, on November 5, 2009 the OTC member states called on the EPA to promulgate federal regulations based on the successful regional and local control strategies and programs implemented in the OTC states; and,

Whereas, implementing such measures on a national basis will protect the public by substantially reducing the ozone and particulate pollution that causes unhealthful air, results in respiratory illness and premature deaths, and contributes to the environmental degradation of our natural resources;

THEREFORE, BE IT RESOLVED, with added urgency, that the OTC member states continue to call upon EPA to create strong national rules that regulate the following six categories, which are responsible for approximately 75% of NOx emissions (and 85% of SO2 emissions) left to regulate:

1. Electricity Generating Units (EGUs)

2. Onroad mobile gasoline and diesel sources

3. Industrial, Commercial and Institutional (ICI) Boilers

4. Cement Kilns

5. Locomotive engines and

6. Marine Engines.

BE IT FURTHER RESOLVED that the EPA should develop and implement strong national programs for the following additional sources (in the order of their relative priority):

1. Stationary Reciprocating and Combustion Engines and Distributed Generation

2. Consumer and Commercial Products
   - Consumer Products
   - Architectural, Industrial and Maintenance Coatings
   - Adhesives, Sealants Primers and Solvents

3. Other Industrial Sources
   - Asphalt Production and Paving
   - Glass Manufacturing
   - Mobile Equipment Repair and Refinishing
   - Solvent Cleaning Operations

BE IT FURTHER RESOLVED that all of these national rules should reduce emissions to the maximum extent feasible, but at minimum meet current or proposed OTC model rule standards or recommendations, and should be in addition to the EPA updating its requirements for nonattainment areas to adopt and implement reasonable available controls.

Adopted on June 3, 2010

Laurie Burt

Laurie Burt, Chair

Air Quality Screening Modeling

Emissions and Photochemical Modeling

OTC Modeling Committee Meeting

September 16, 2010

Baltimore, MD

OZONE TRANSPORT COMMISSION

Screening Runs

Purpose

Investigate the level of emissions reductions needed to achieve the current NAAQS of 75 ppb and the potentially lower new NAAQS in the 60 to 70 ppb range

Design of the exercise

Perform screening simulations with existing data applying theoretical across-the-board reduction in emissions, as well as a simulation approximating OTC-recommended national and local measures

Modeling Approach

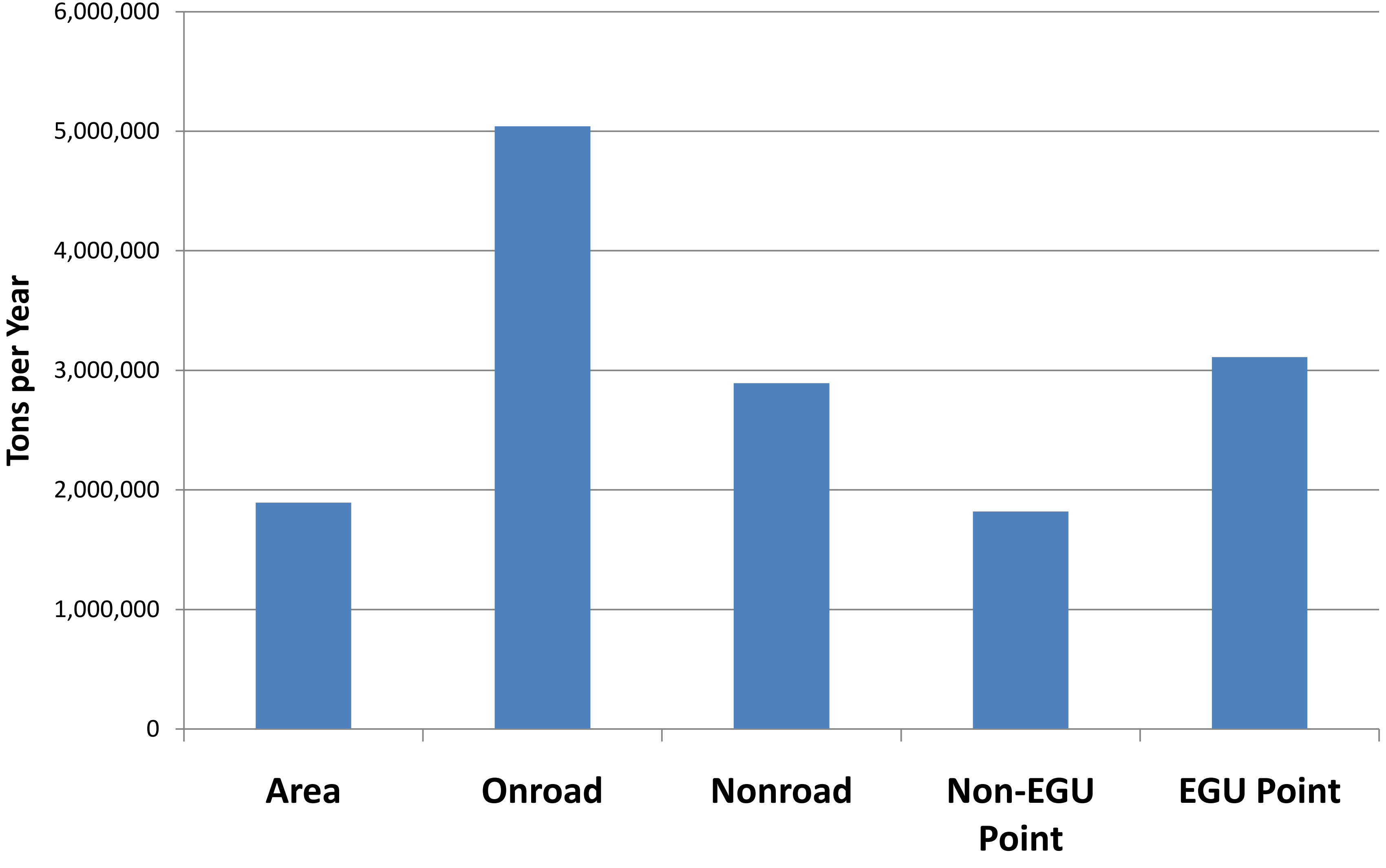
- 2007 Meteorology replicated by WRF
- Man-made Proxy Emissions:
  - Actual 2007 for point and non-road sources within MANE-VU
  - Other point sources from EPA CHIEF 2005 Platform
  - Remaining source sector emissions were interpolated from 2002 and 2009 inventories from 2002 SIP platform
- 2007 Natural emissions based on MEGAN
- Photochemical model – CMAQv4.7 with CB5 chemistry
- Modeling domain: 12 km Eastern U.S.
- Boundary conditions always kept at “clean” background levels
- Modeling period: April 1 – October 31 for base case

Participants in this Effort

- NJDEP/ORC
- UMD/MDE
- NYSDEC
- MARAMA
- OTC

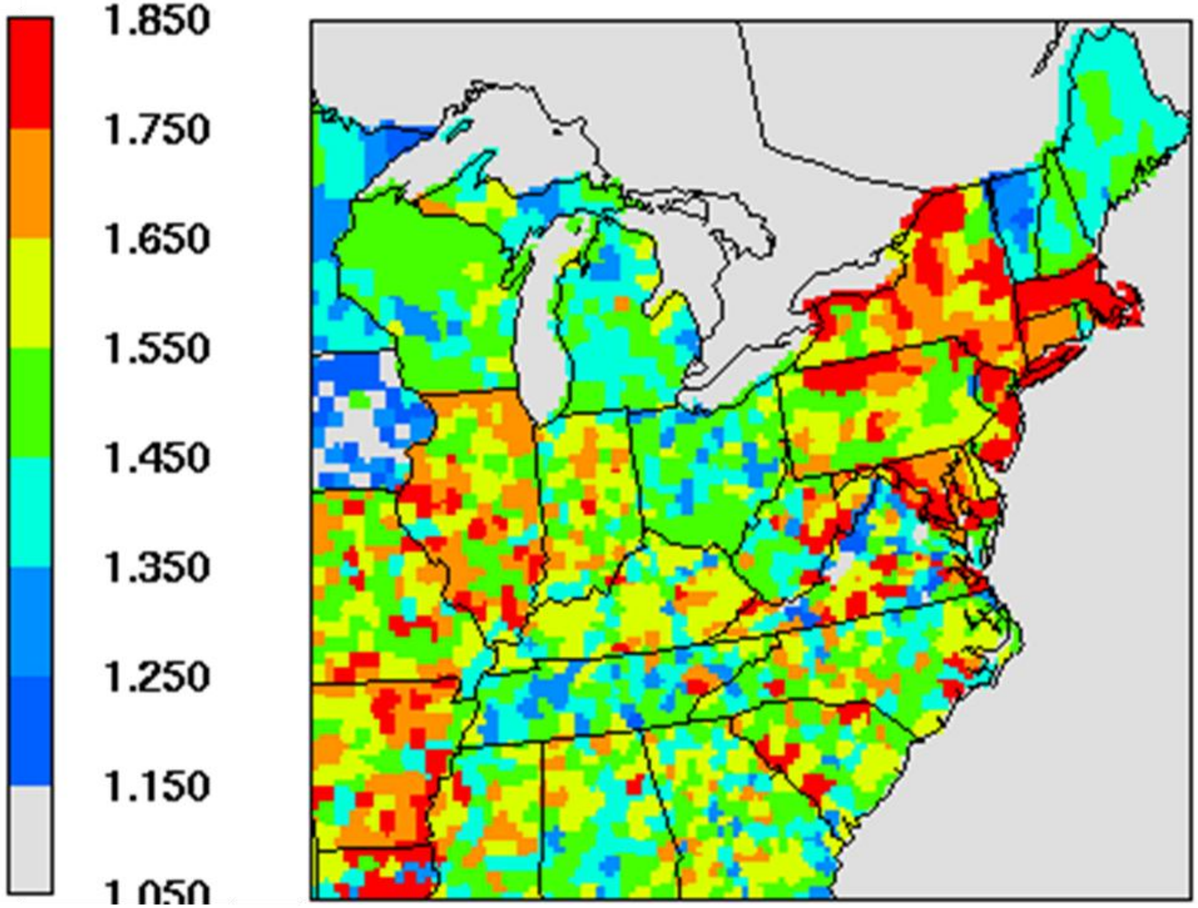
Domain-wide NOx Emissions*

2007 Proxy Inventory



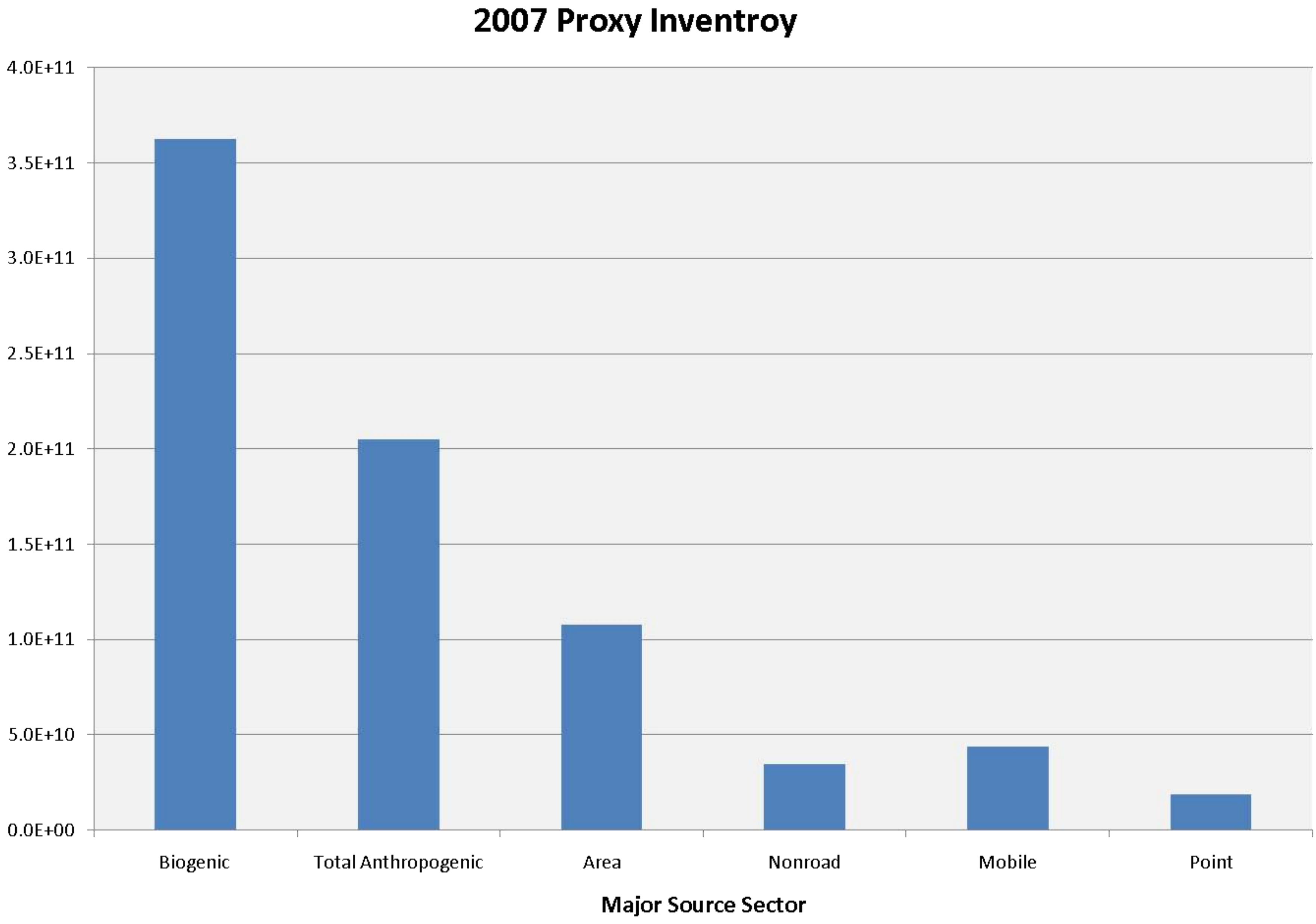
*Includes MOVES adjustments to MOBILE6 emissions

NOx MOVES/NOx Mobile 6 Ratio (August)



- MOVES emissions are 60-80 % higher than Mobile-6
- MOVES emissions based on EPA provided data to approximate MOVES model output

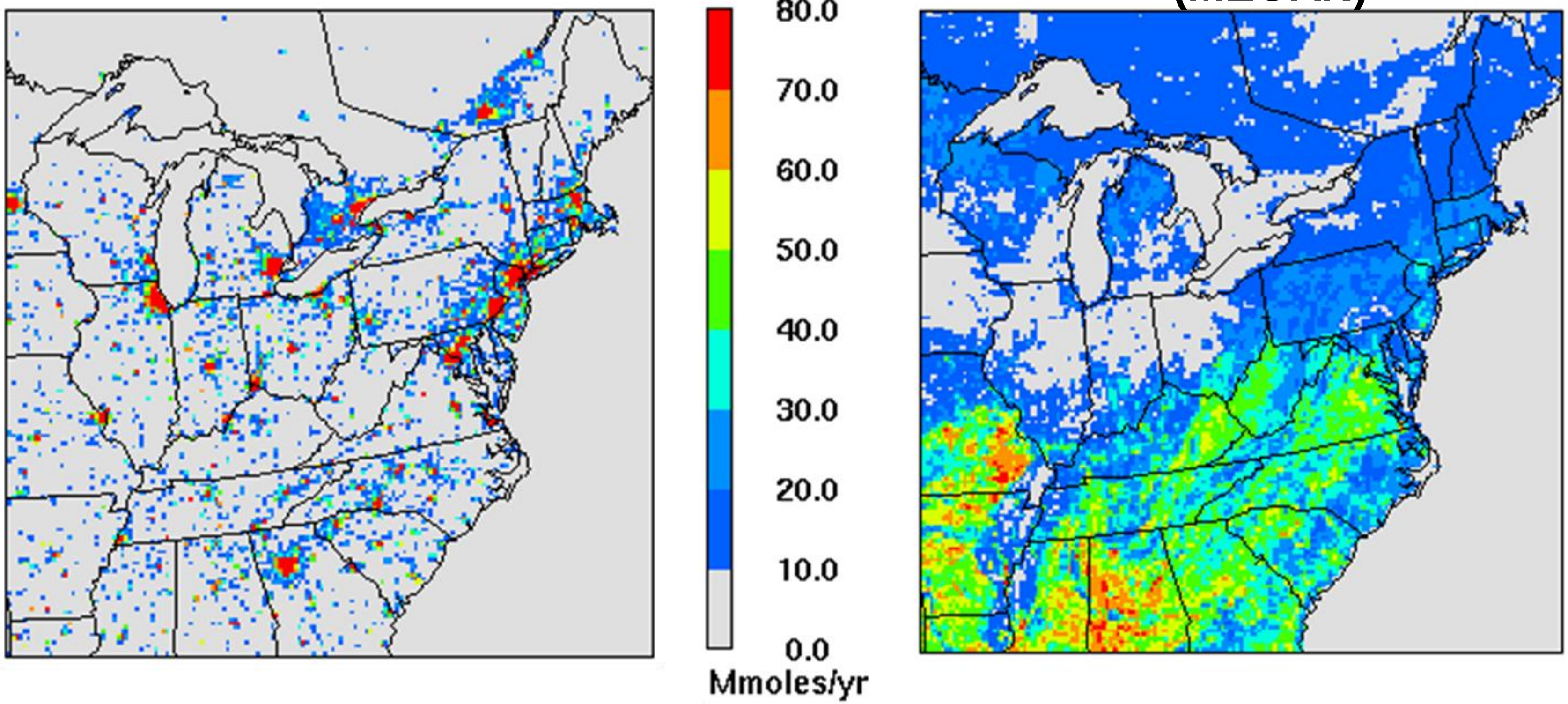
Domain-Wide VOC Emissions



Distribution of Domain VOC Emissions

Man-Made VOC Emissions

Natural VOC Emissions (MEGAN)

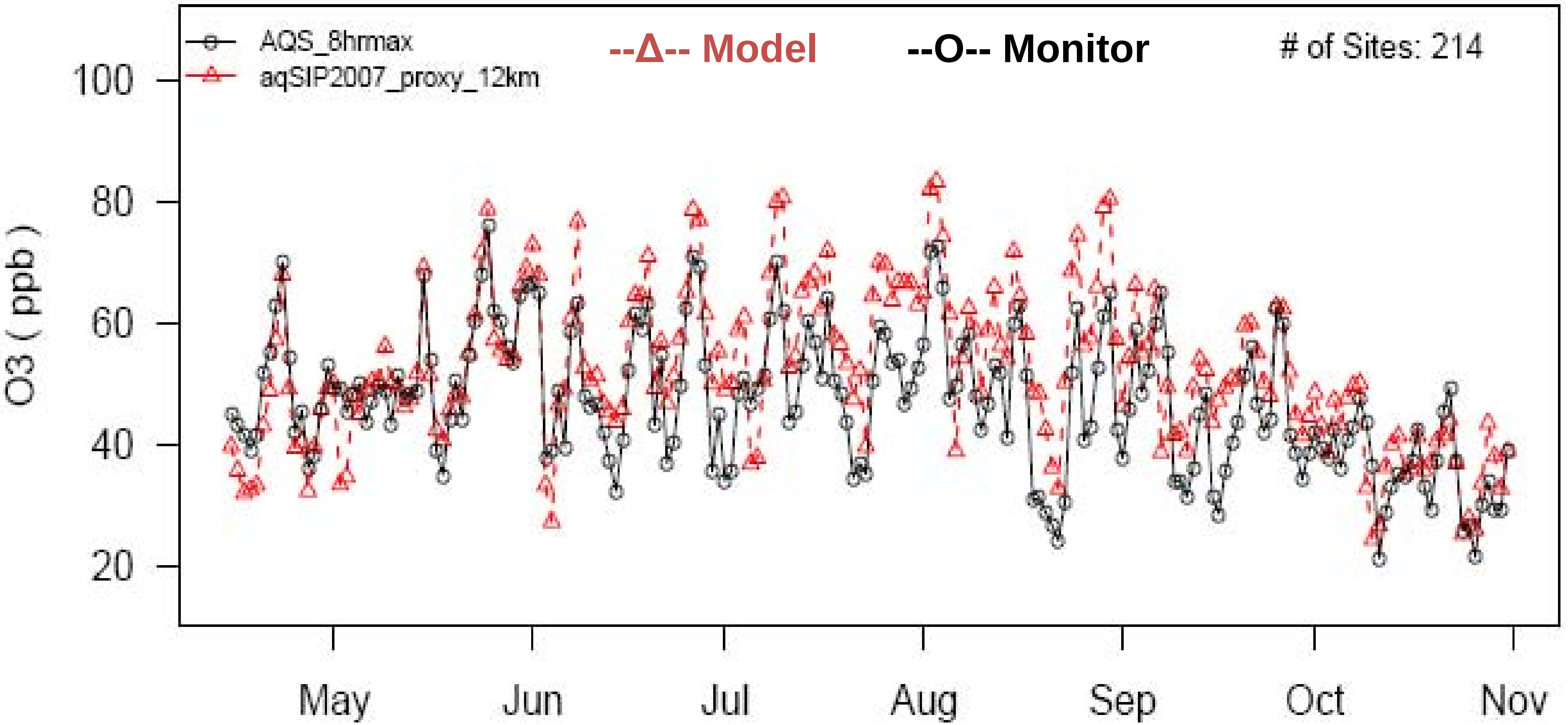


- Man-made VOC emissions are dominant in urban areas
- Natural VOC emissions are dominant in forested areas, especially in the south

Model Performance

Time Series Comparison

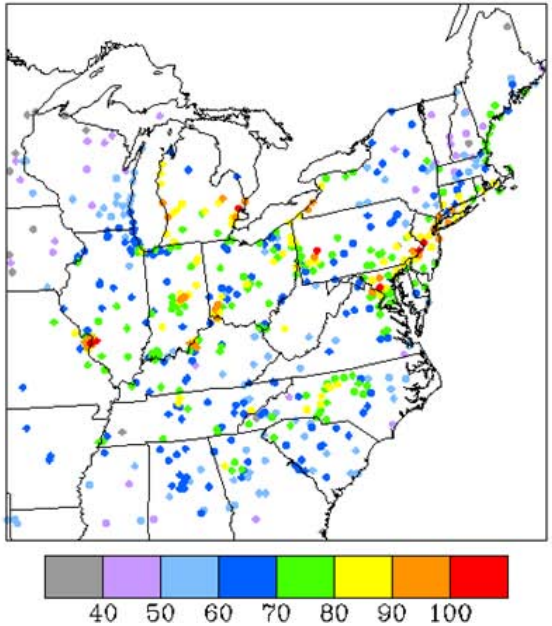
Model vs. Monitored 8-hour Ozone, OTC States

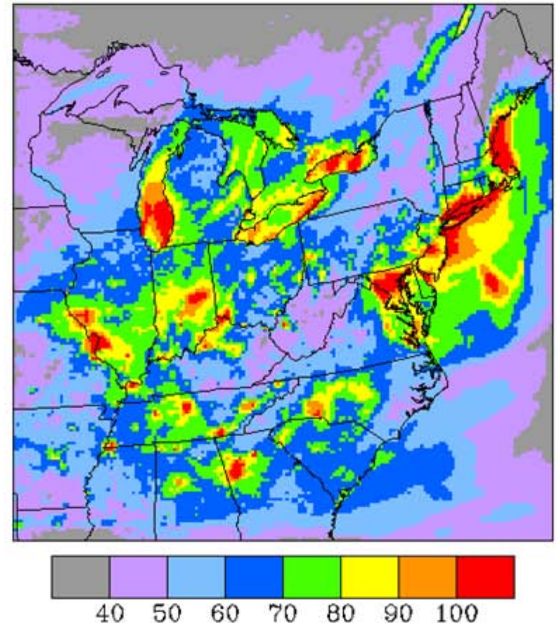


- The timing of episodes is generally captured, but their magnitude tends to be overestimated

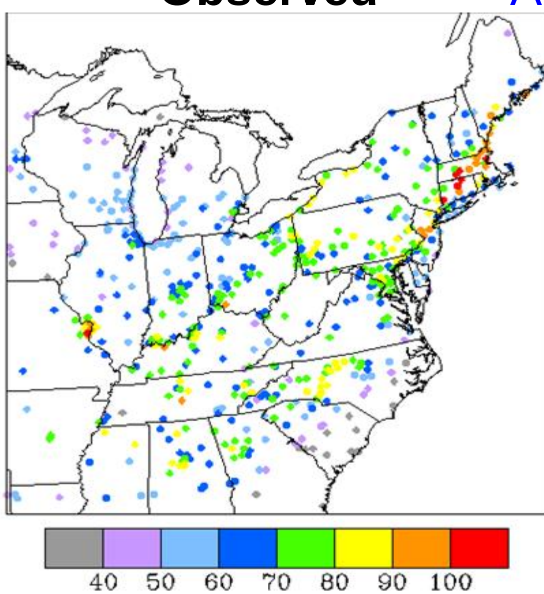
Model Performance During Ozone Episode

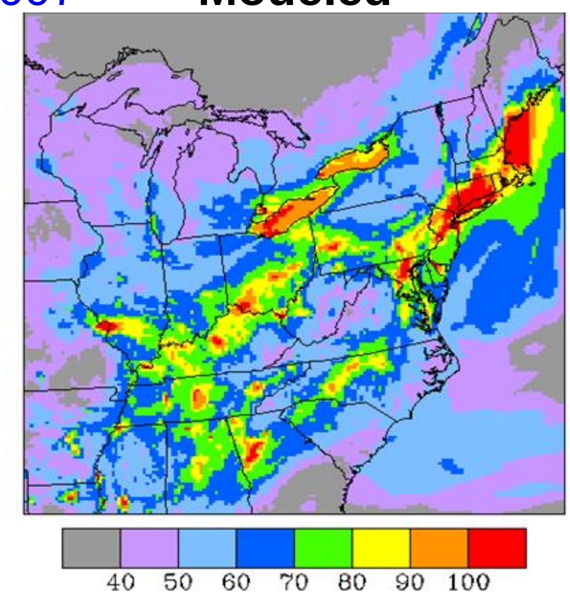
Observed August 2, 2007 **Modeled**





Observed August 3, 2007 **Modeled**





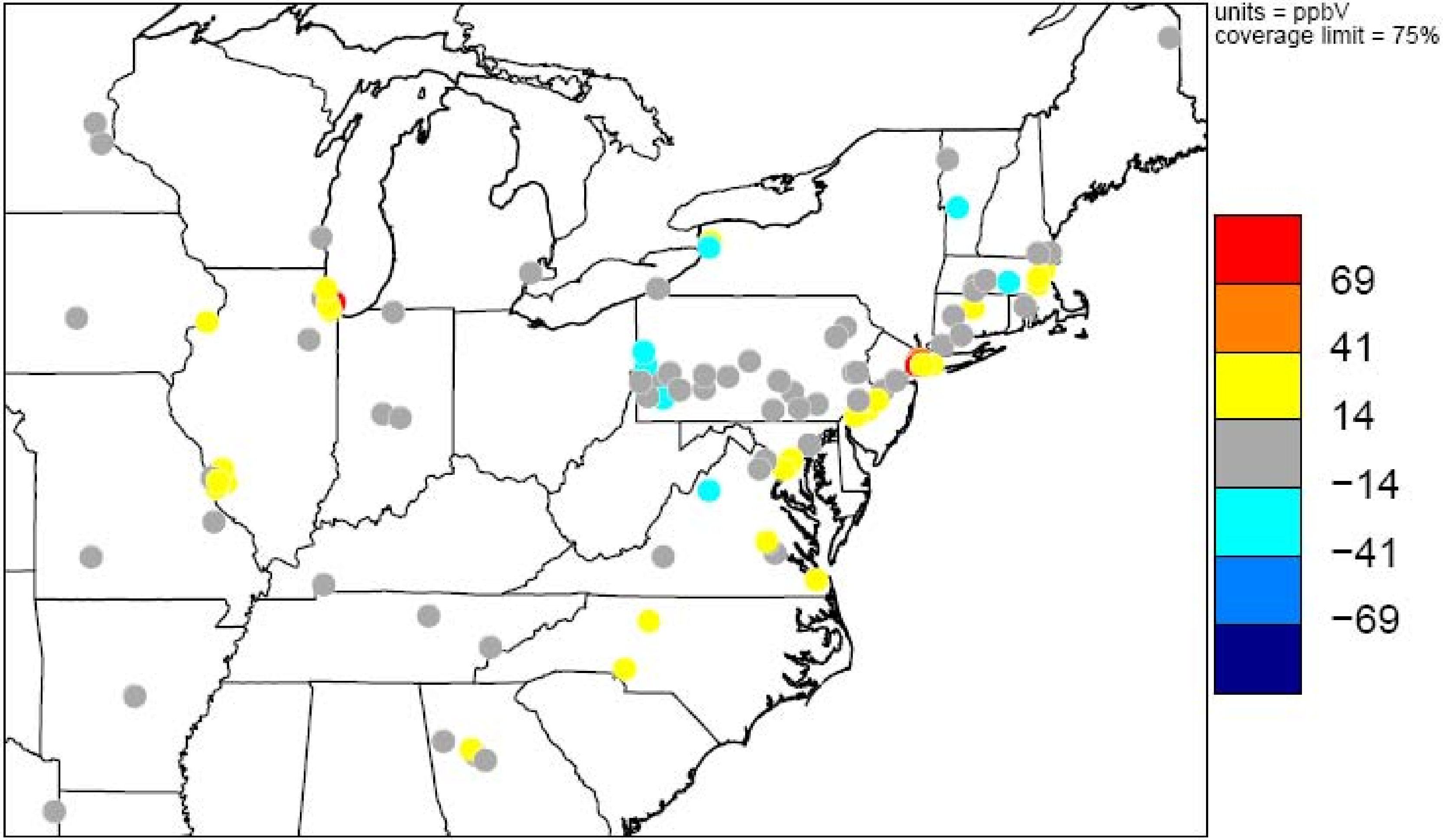
Summary Model Performance Statistics for Daily Maximum 8-hour Ozone

Region	Data Pairs	Mean Observed	Mean Model	Mean Bias (ppb)	Mean Error (ppb)	Normalized Mean Bias (Percent)	Normalized Mean Error (Percent)	Root Mean Square Error (ppb)	Correlation Coefficient
Domain-wide	115,712	49.7	51.9	2.2	9.5	4.4	19.2	12.4	0.7
OTC States	39,320	47.6	52.7	5.0	10.3	10.6	21.5	13.4	0.73

- Model performance is within the range of previous studies

Mean Bias of 6am-9am Average NOx Concentrations

Model minus Observed



Screening Simulations

Two theoretical simulations with across-the board reductions on all man-made sectors throughout domain:

Screening simulation 1:

50% NOx and 30% VOC reductions (“N50V30”)

Screening simulation 2:

70% NOx and 30% VOC reductions (“N70V30”)

These simulations were performed for April 1 – October 31, 2007

Screening Simulations (continued)

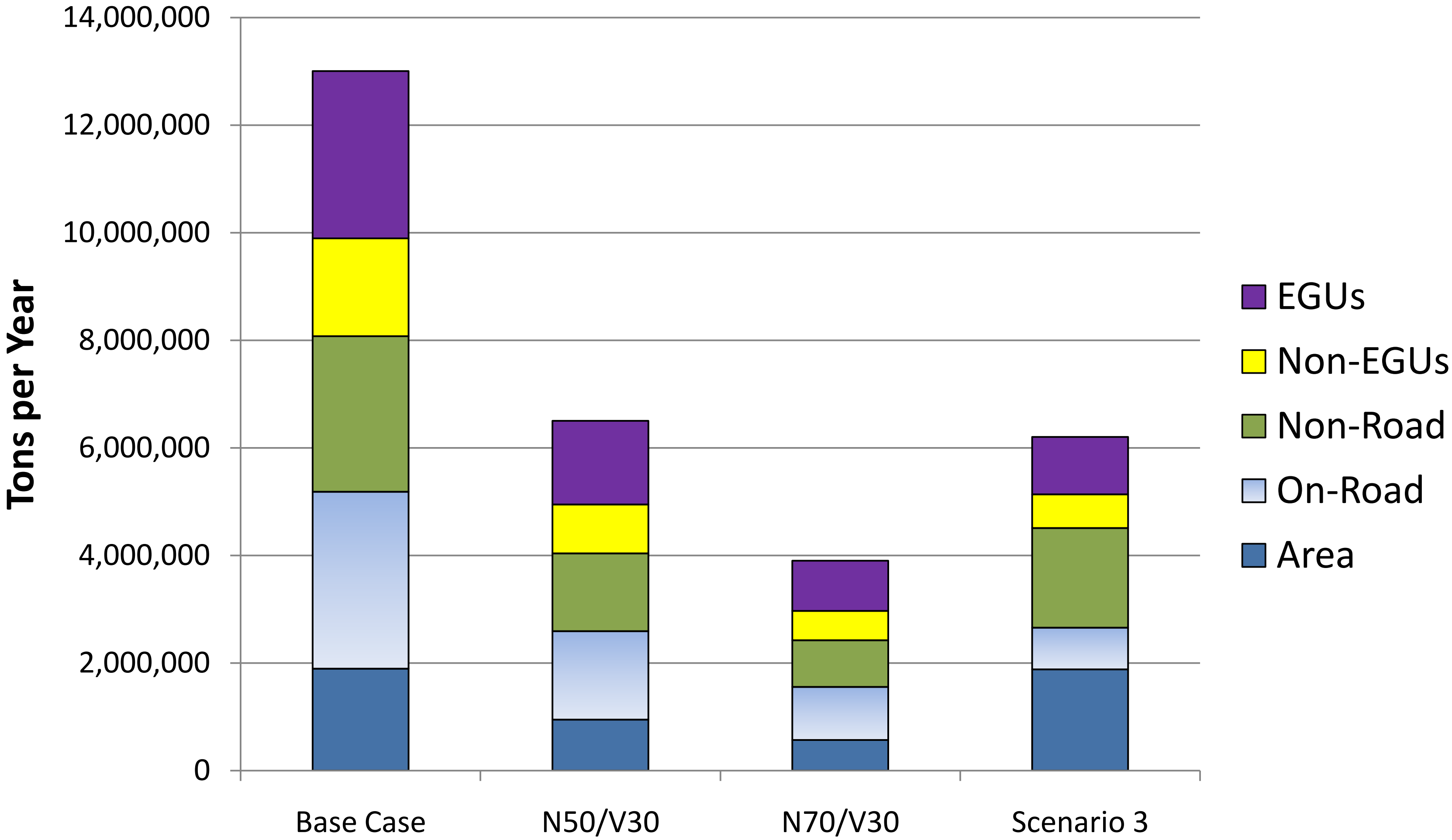
Screening simulation 3:

Approximates OTC's recommendation for critical national reductions combined with local OTR measures

- VOC: 30% reduction for all sectors across entire modeling domain
- NOx Domain-wide:
  - Point: 65% reduction (includes reductions from ICI boilers and cement kilns and a 900,000 ton regional trading cap on EGUs)
  - On-road: 75% reduction (approximates a 2020 national LEV 3)
  - Non-road: 35% reduction (includes reductions from marine and locomotive engines)
- NOx in OTR States:
  - Additional 5% reduction across all sectors in the OTR

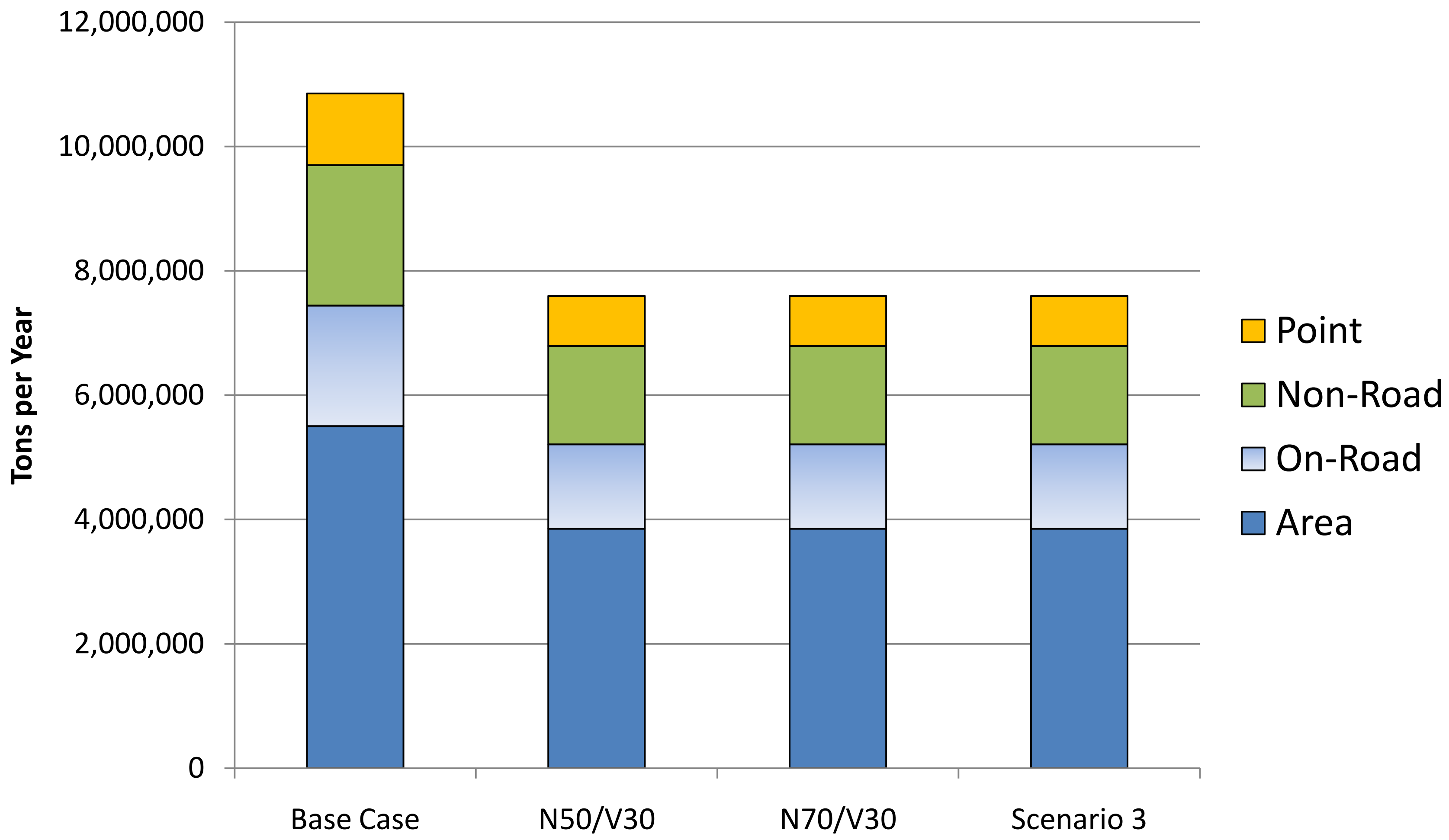
This simulation was performed for May 15 – August 31

NOx Emissions in Screening Runs



- "Scenario 3" approximates an overall 55% NOx reduction
- Includes MOVES adjustments to MOBILE6 emissions

VOC Emissions in Screening Runs



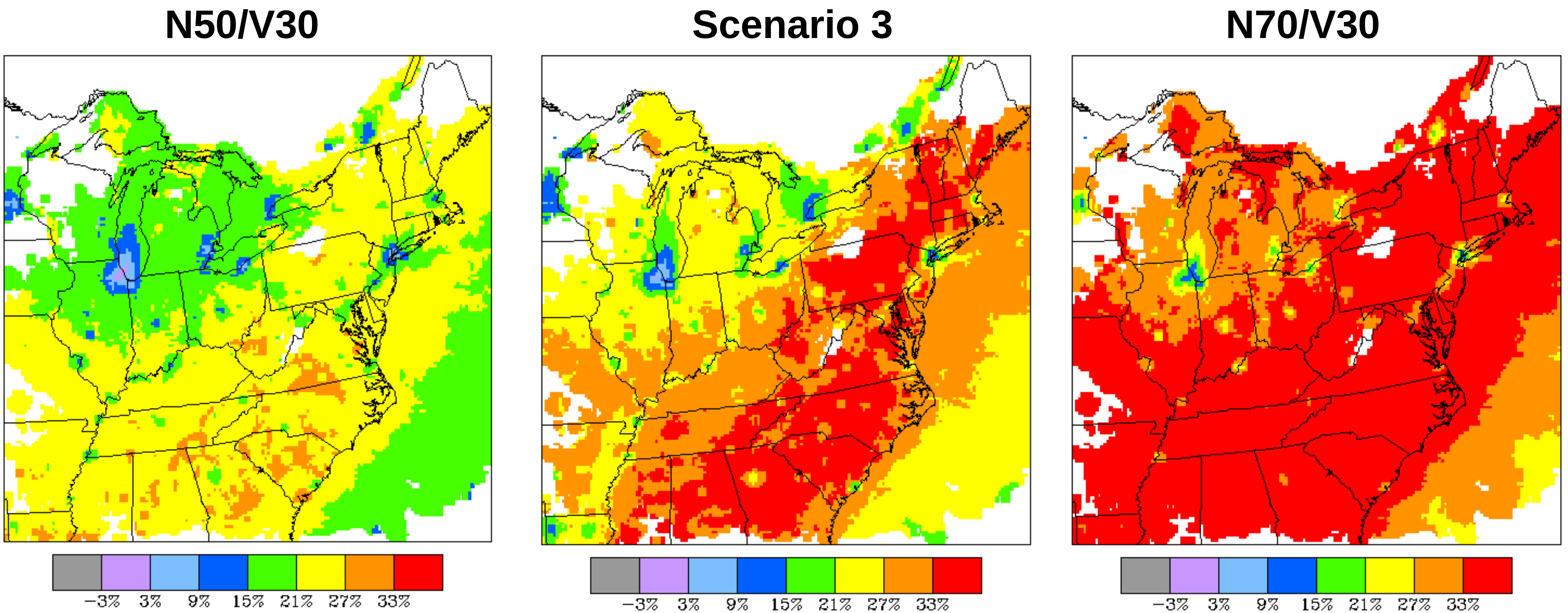
- All screening runs reduce VOC emissions by 30%.
- Includes MOVES adjustments to MOBILE6 emissions

Results

N50V30, N70V30, and “Scenario 3” Simulations

June 1 – August 31

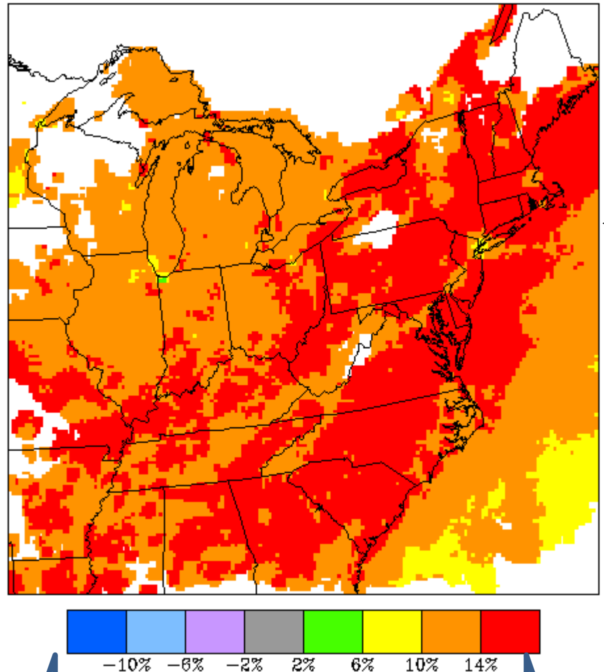
Relative Ozone Reductions



- Ozone reductions from "Scenario 3" run fall between those from the across-the-board reduction simulations
- NO_x focused emission reductions show less benefit for urban core areas

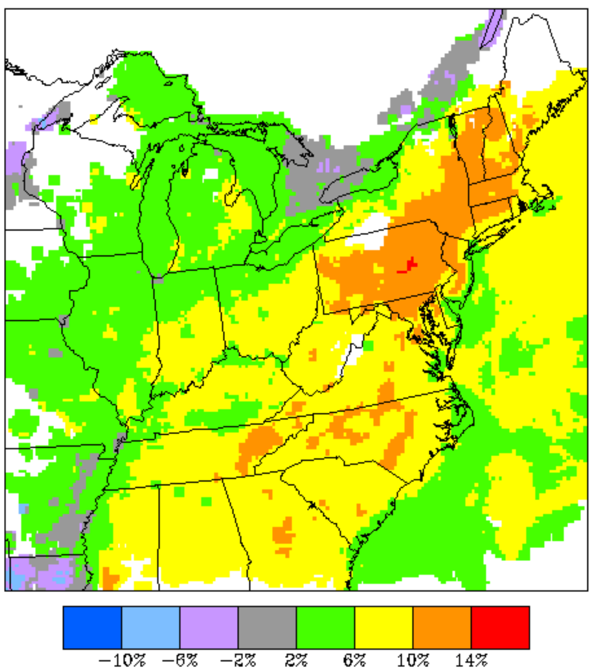
Differences in Relative Ozone Reductions

N70V30 Minus N50V30



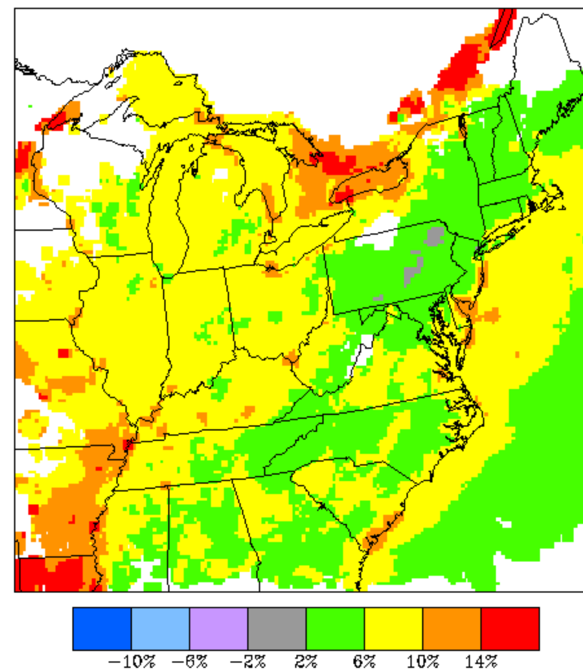
Additional benefit of N70/V30 compared to N50/V30

Scenario 3 Minus N50V30



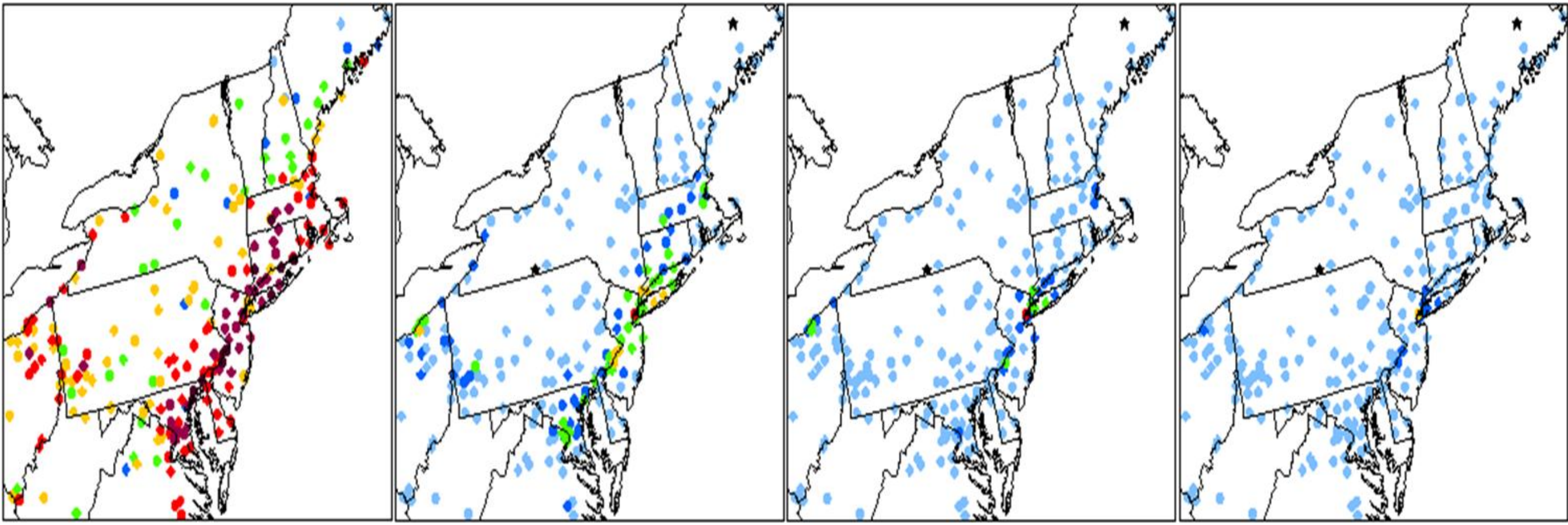
For most of the OTR, "Scenario 3" provides more than **50%** of the additional benefit of N70/V30 compared to N50/V30

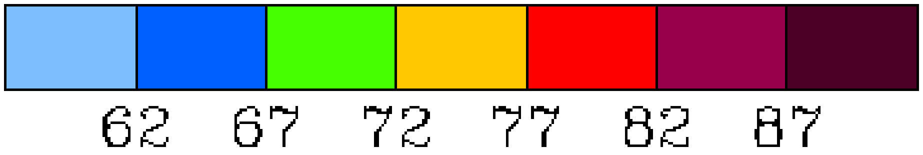
N70V30 Minus Scenario 3



Observed & Predicted Ozone Concentration Design Values

Observed 2005-09 | N50V30 | Scenario 3 | N70V30

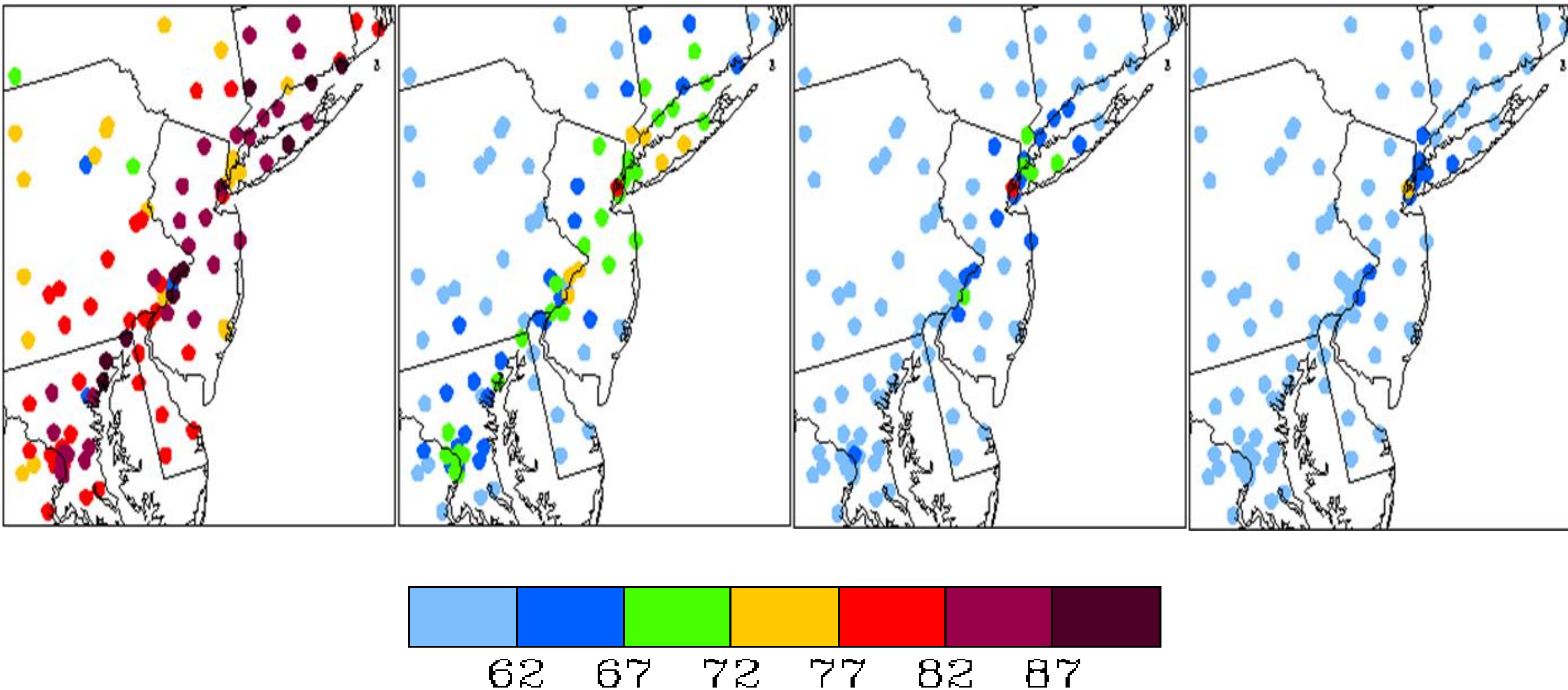




- In N50/V30 across-the-board reductions, hot spots remain in urban areas
- Hot spots are further reduced in “Scenario 3” and N70/V30 reduction scenarios

Observed & Predicted Ozone Concentration Design Values

Observed 2005-09 | N50V30 | Scenario 3 | N70V30



- In N50/V30 across-the-board reductions, hot spots remain in urban areas
- Hot spots are further reduced in “Scenario 3” and N70/V30 reduction scenarios

Monitors at Nonattainment Levels

	Base Case		N50/V30		N70/V30		"Scenario 3"	
.08 ppm	34	(18%)	0	(0%)	0	(0%)	0	(0%)
.070 ppm	167	(86%)	16	(8%)	1	(0%)	1	(0%)
.065 ppm	186	(96%)	55	(29%)	4	(2%)	12	(6%)
.060 ppm	191	(98%)	101	(53%)	15	(8%)	29	(15%)
Monitors in OTR	194		190		190		190	

Caveats

- These screening runs use proxy emissions through interpolated inventories for many sectors and regions
- Simplified “MOVES-like” adjustment to MOBILE6 emissions have not been fully tested
- Use of “time invariant clean” boundary conditions
- Screening simulations are based on simplified across-the-board emission reduction approaches

Technical Conclusions

- 2007 Meteorology (WRF) simulation appears to have captured the episode and non-episode periods over the modeling domain as evidenced from observed and predicted ozone pattern

- Ozone levels are somewhat overestimated during episodes over the OTC states – One potential cause could be impact from increased mobile source NO_x from the adoption of MOVES-like mobile source emissions

- In general the N70/V30 reduction case provides increased response of 7 to 11 ppb over N50/V30

- All screening simulations generally give lower ozone reductions in core urban areas such as Bayonne, NJ and Bronx, NY

Policy Conclusions

- An aggressive suite of national measures (in combination with local measures in the OTR) in some targeted sectors as recommended by OTC should help all of the OTR states attain the new standard
- A 50% across the board reduction appears to fall somewhat short of what is needed for full attainment, particularly for the I-95 corridor
- A 70% across-the-board reduction appears to get most areas of the OTR into the low range (60-65 ppb) of the proposed ozone NAAQS
- “Scenario 3” (approximately a 55% reduction) brings several areas of the OTR into the middle of the proposed range

Ongoing Activities: CMAQ Benchmarking

- Benchmarking of CMAQ between participating modeling centers: NJDEP/ORC, UMD, VADEQ, NESCAUM, and NYSDEC
- Goal: Ensure consistency between modeling centers when collaborating on performing the next round of simulations
- Benchmark package consists of
  – CMAQv4.7.1 statically compiled executable
    - CMAQ4.7.1 was released in July 2010 after the completion of the screening simulations
    - No major science updates compared to CMAQ4.7 used in the screening simulations
  – Input files (meteorology, emissions, photolysis rates, initial and boundary conditions)
  – Run scripts

Ongoing Activities: CMAQ Benchmarking

- Benchmark Simulations:
  Modeling period of July 18 – August 9, 2007, for both the 2007 proxy base case and the N50/V30 sensitivity case

- Initial findings:
  Identical results from all modeling centers when using a common statically compiled executable, small differences when using locally compiled executables

Future Activities: Updated Modeling

- Utilize 2007 emission inventories for all sectors and regions
- 36 km continental U.S. and 12 km eastern U.S. simulations with boundary conditions for the 36 km domain obtained from global simulations performed by Georgia DEP
- Extensive model evaluation
- Future year simulations

Extra Slides
Results

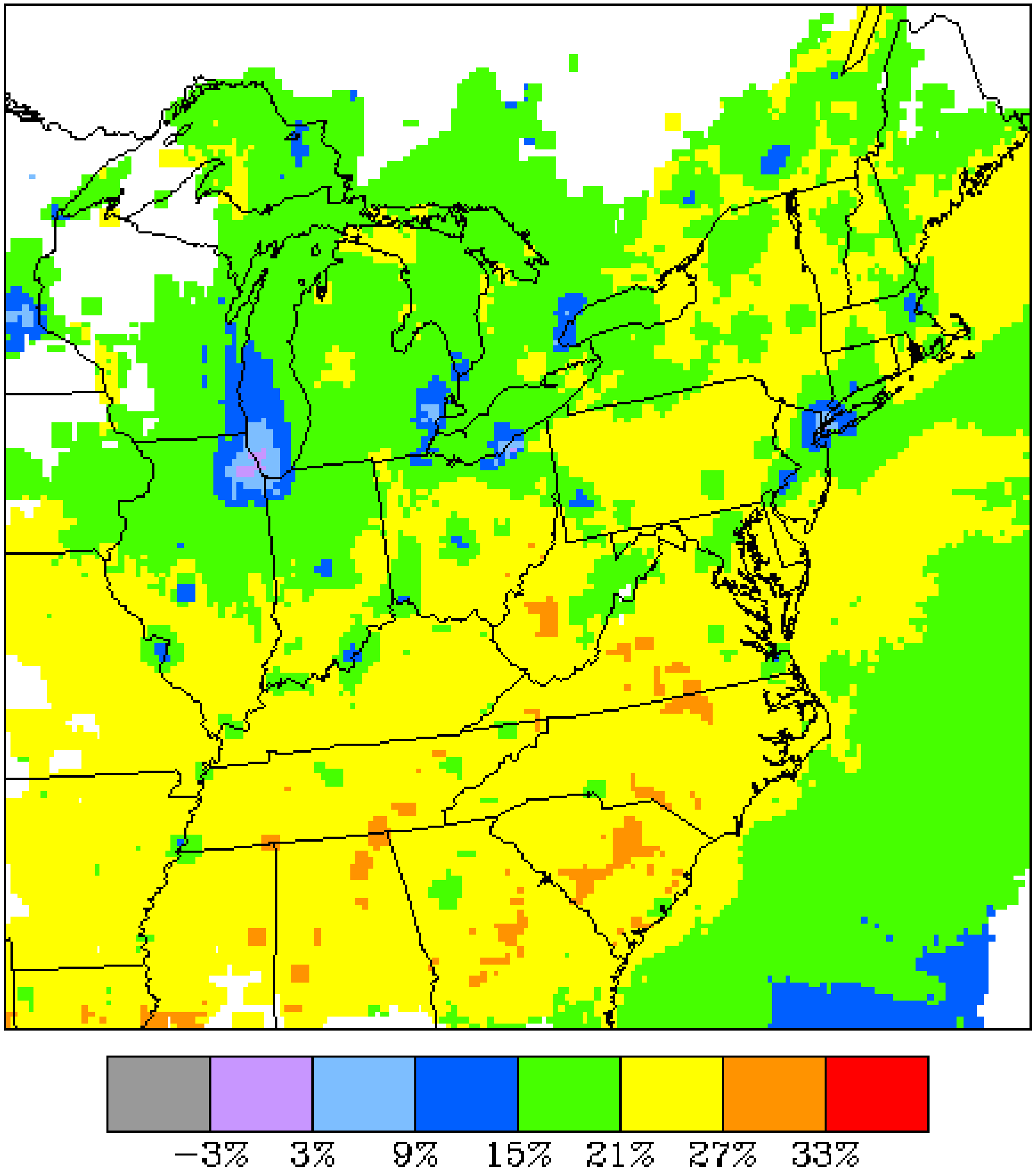
N50V30 and N70V30 Simulations

Analysis Period: April 15 – October 31 (previously shown at June state caucus)

Screening Modeling Results by Monitor, June – August Simulations

Monitor	NAA	DVC 2005 - 2009	DVF 50%NOx/30%VOC	DVF OTC Recommendations	DVF 70%NOx/30%VOC
Bayonne	New York-N. New Jersey-Long Island;NY-NJ-CT	85	81	78	74
Bristol	Philadelphia-Wilmin-Atlantic Ci;PA-NJ-MD-DE	90	76	67	64
Camden	Philadelphia-Wilmin-Atlantic Ci;PA-NJ-MD-DE	87.5	75	68	65
White Plains	New York-N. New Jersey-Long Island;NY-NJ-CT	86.3	75	70	66
Babylon	New York-N. New Jersey-Long Island;NY-NJ-CT	85.3	74	69	64
NEA	Philadelphia-Wilmin-Atlantic Ci;PA-NJ-MD-DE	88	74	65	62
Greenwich	New York-N. New Jersey-Long Island;NY-NJ-CT	86.3	73	67	61
Holtsville	New York-N. New Jersey-Long Island;NY-NJ-CT	88	73	66	61
Clarksboro	Philadelphia-Wilmin-Atlantic Ci;PA-NJ-MD-DE	85.7	72	64	61
Rudgers U	New York-N. New Jersey-Long Island;NY-NJ-CT	86.3	72	63	60
NYC-Queens	New York-N. New Jersey-Long Island;NY-NJ-CT	76.7	72	69	67
Stratford	New York-N. New Jersey-Long Island;NY-NJ-CT	87	71	64	58
McMillan Reservoir	Washington; DC-MD-VA	84.7	71	63	60
Rider U	Philadelphia-Wilmin-Atlantic Ci;PA-NJ-MD-DE	86.3	71	62	59
Ramapo	New York-N. New Jersey-Long Island;NY-NJ-CT	85.3	71	63	61
NYC-IS52	New York-N. New Jersey-Long Island;NY-NJ-CT	73.3	71	68	66

Relative Ozone Reductions
Due to 50% NOx and 30% VOC Reductions

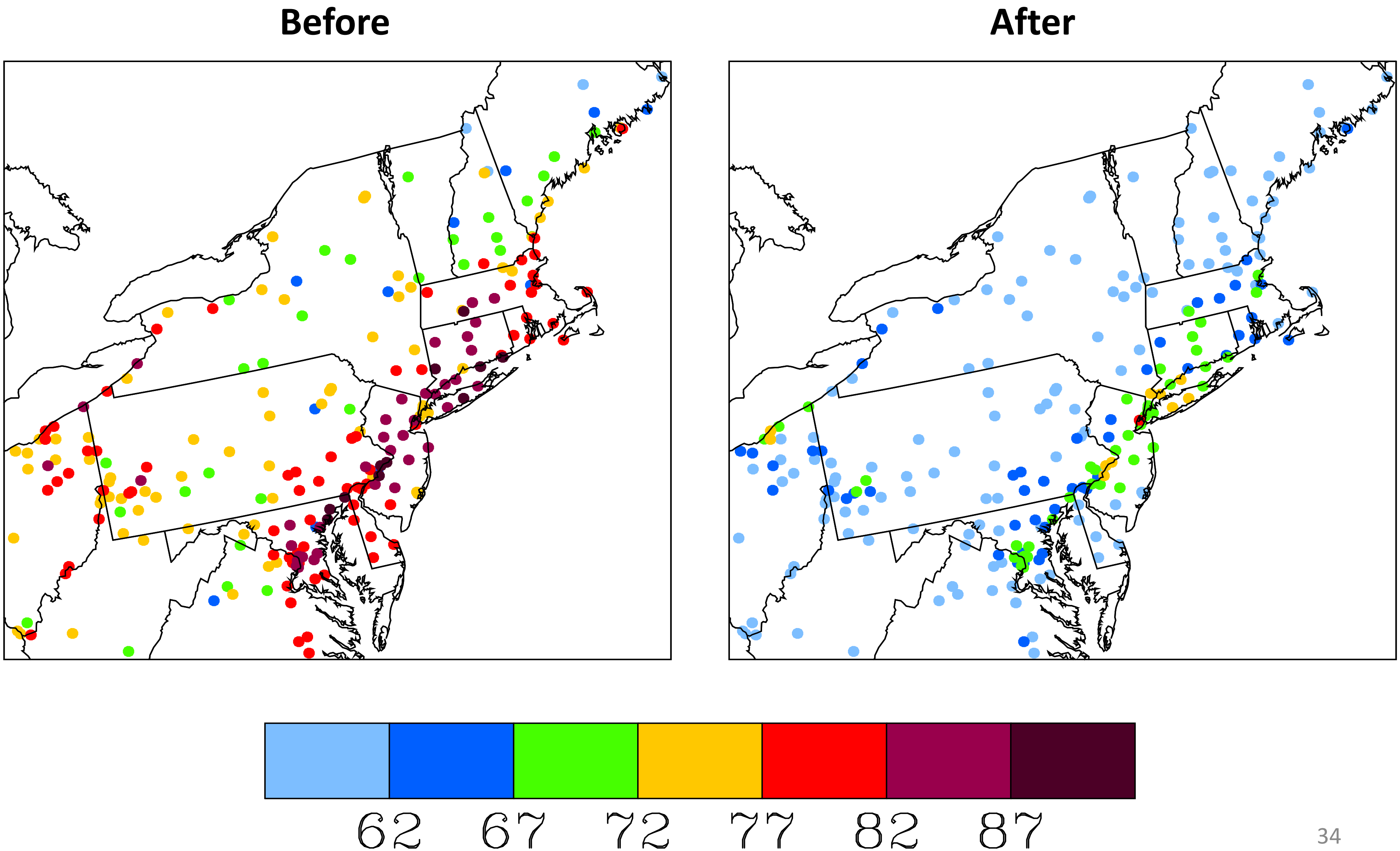


NO_x- focused emission reductions show less benefit for urban core areas

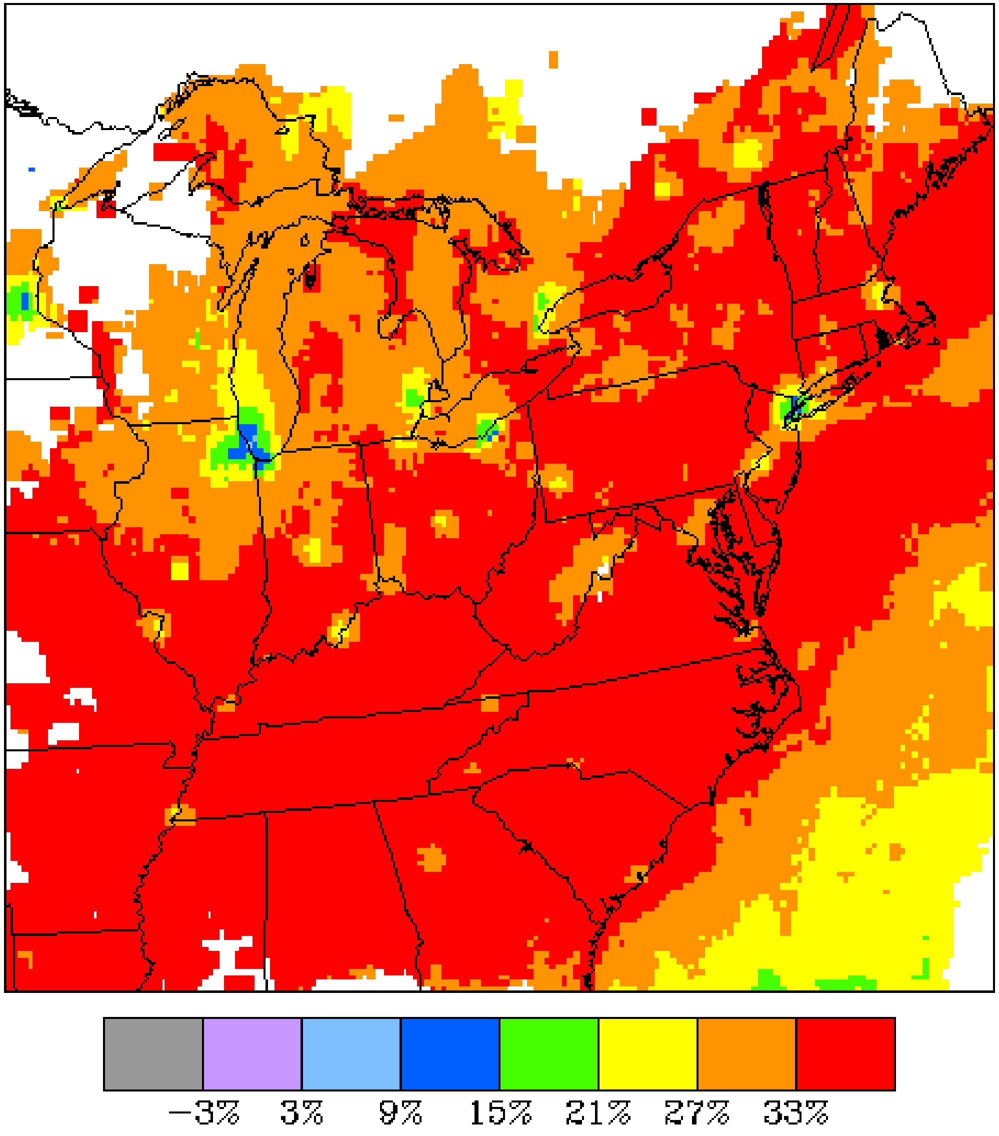
Model Predicted Ozone Concentration Design Values

With 50% NOx and 30% VOC Reductions Across-the-Board

Hot Spots remain in Urban Areas



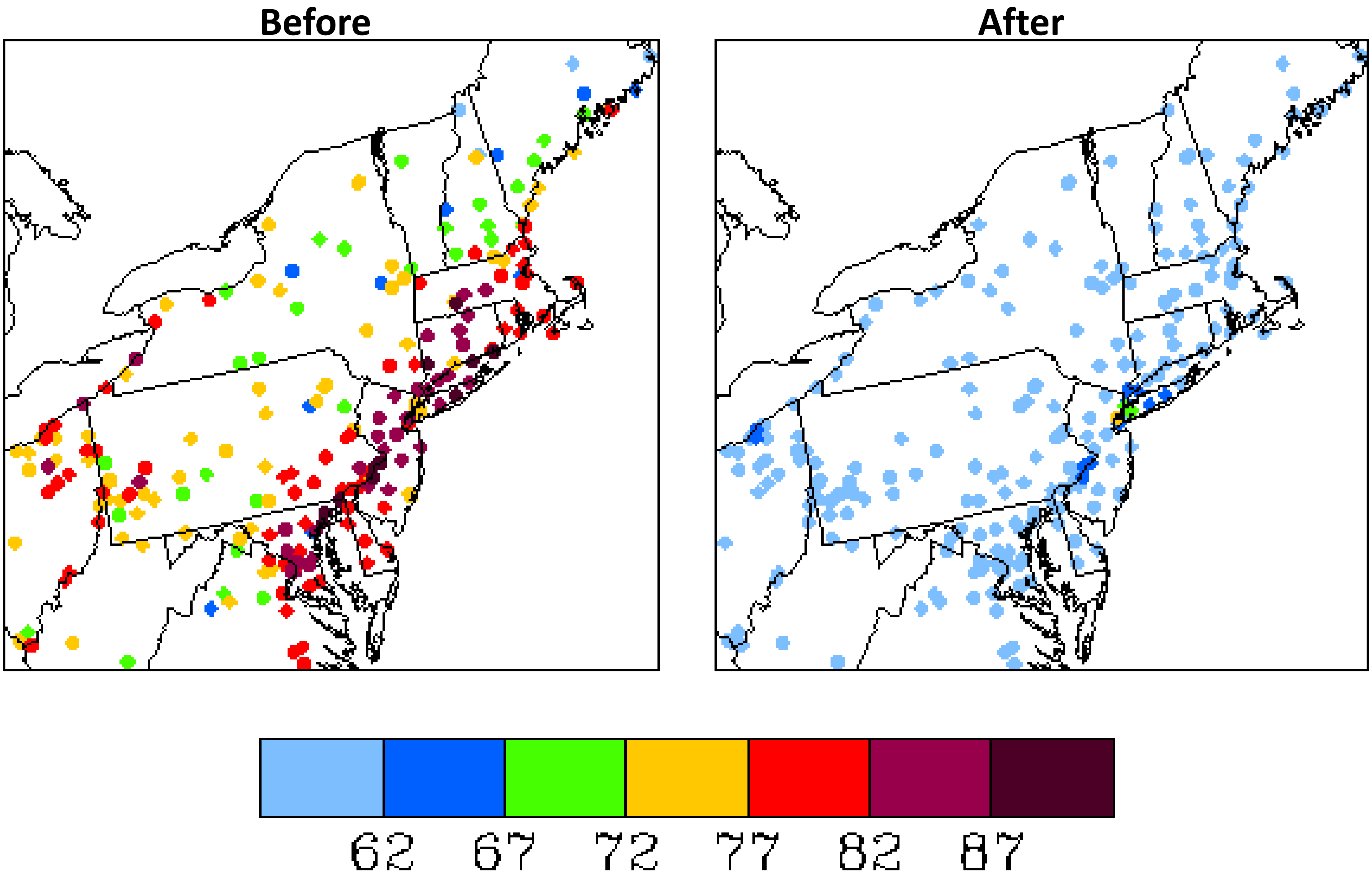
Relative Ozone Reductions
Due to 70% NOx and 30% VOC Reductions



- Larger ozone reductions throughout than earlier screening run.
- Overall ozone reductions generally greater than 27% except for core urban areas.

Model Predicted Ozone Concentration Design Values

With 70% NOx and 30% VOC Reductions Across-the-Board



Screening Modeling Results by Monitor

April – October "Across-The-Board" Simulations

Monitor	NAA	DVC 2005 - 2009	DVF 50%NOx/30%VOC	DVF 70%NOx/30%VOC
Bayonne	New York-N. New Jersey-Long Island;NY-NJ-CT	85	81	74
Bristol	Philadelphia-Wilmin-Atlantic Ci;PA-NJ-MD-DE	90	77	66
White Plains	New York-N. New Jersey-Long Island;NY-NJ-CT	86.3	76	67
Babylon	New York-N. New Jersey-Long Island;NY-NJ-CT	85.3	76	66
Camden	Philadelphia-Wilmin-Atlantic Ci;PA-NJ-MD-DE	87.5	75	65
NEA	Philadelphia-Wilmin-Atlantic Ci;PA-NJ-MD-DE	88	75	64
Greenwich	New York-N. New Jersey-Long Island;NY-NJ-CT	86.3	74	63
Holtsville	New York-N. New Jersey-Long Island;NY-NJ-CT	88	74	63
Stratford	New York-N. New Jersey-Long Island;NY-NJ-CT	87	73	61
NYC-IS52	New York-N. New Jersey-Long Island;NY-NJ-CT	73.3	72	68
NYC-Queens	New York-N. New Jersey-Long Island;NY-NJ-CT	76.7	72	68
Ramapo	New York-N. New Jersey-Long Island;NY-NJ-CT	85.3	72	62
Clarksboro	Philadelphia-Wilmin-Atlantic Ci;PA-NJ-MD-DE	85.7	72	61
Rider U	Philadelphia-Wilmin-Atlantic Ci;PA-NJ-MD-DE	86.3	72	61
Rutgers U	New York-N. New Jersey-Long Island;NY-NJ-CT	86.3	72	60
NYC-Susan Wagner HS	New York-N. New Jersey-Long Island;NY-NJ-CT	80.7	71	63
Lynn	Boston-Lawrence-Worcester (E. MA); MA	81.3	71	61
Westport	New York-N. New Jersey-Long Island;NY-NJ-CT	85.3	71	60
McMillan Reservoir	Washington; DC-MD-VA	84.7	71	60
Chicopee	Springfield (Western MA); MA	88	71	59
Danbury	New York-N. New Jersey-Long Island;NY-NJ-CT	88.7	71	58
Middletown	New York-N. New Jersey-Long Island;NY-NJ-CT	87	71	58

Appendix 10

OTC Detailed Comments on Modeling and Technical Analysis

Air Quality Assessment Tool (AQAT)

In its analysis to quantify the impacts of emission reductions at various cost levels on air quality at downwind receptor sites, EPA relied heavily on the AQAT, a simplified modeling tool developed by EPA for this task to speed up the modeling process. While we appreciate the need for quick analyses, OTC is concerned about the precedent set by EPA as applied to major rules, especially in the future. We understand that in developing the proposed Transport Rule, EPA has a base of existing modeling and technical analysis for CAIR that, while not directly applicable to this effort, does provide some foundation for understanding the issues with and magnitude of the design of a remedy. However, there are existing techniques, which we discuss below, that are available and that EPA should use in completing its analysis for the final Transport Rule, and also for Transport 2.

OTC believes that AQAT tool makes several over-simplifying assumptions, the first in regards to the direct proportionality between reductions of upwind emissions and downwind ambient concentrations and the second that emission reductions from all source sectors are equally effective in reducing downwind concentrations. These assumptions are especially problematic in our highly populated region due to complex topography and sharp gradients of air pollution concentrations.

Analysis presented in the Preamble and the Significant Contribution Technical Support Document (SC-TSD) indicates that the AQAT has overestimated the air quality benefits resulting from the 2014 remedy emission scenario in direct comparison to the analysis of the more detailed Comprehensive Air Quality Model with extensions (CAMx) modeling for the case of daily $PM_{2.5}$. The results presented in Table 4.2 of the SC-TSD indicate that AQAT averages about 6 $\mu g/m^3$ more benefit than CAMx resulting from the emission reductions occurring between the 2012 base case to the 2014 proposed remedy case. While CAMx modeling indicates an average $PM_{2.5}$ improvement for this case in the approximate range of 40$\mu g/m^3$ to 34$\mu g/m^3$, AQAT analysis indicates about twice that improvement (reducing the average estimate design value from approximately 40 $\mu g/m^3$ to approximately 28 $\mu g/m^3$). We are concerned about the linear assumptions between NOx and SOx levels during the winter months and the formation of nitrates and sulfates, respectively, employed in AQAT, which as shown in EPA's own analysis, results in an over-prediction of $PM_{2.5}$ reductions in the winter.

The SC-TSD does not present quantitative information for the annual $PM_{2.5}$ or ozone standard that is comparable to the information in Tables 4.1-3 in the SC-TSD. This type of information is needed to gauge whether the use of AQAT is appropriate for those standards. The Preamble states that for the annual $PM_{2.5}$ standard, there are only two monitors for which the AQAT analysis and the more detailed CAMx modeling differ in their attainment / maintenance status classification for the 2014 remedy case. The comparable data would allow this to be confirmed. Although the differences between CAMx and AQAT for this proposed Transport Rule may affect attainment/maintenance status at only a few monitors, we are concerned that the actual reductions may be significant enough to warrant a very limited use of AQAT for future analyses.

In summary, OTC urges EPA to adopt more detailed air quality modeling systems such as CAMx or Community Multiscale Air Quality model (CMAQ) when determining the level of emission reductions needed to address interstate transport. EPA spent a significant amount of time and effort performing numerous IPM simulations for different emission scenarios with the proposed transport rule; however EPA did not adequately characterize the impact of these emission reductions on ambient air quality using the most detailed air quality modeling available. If EPA chooses to introduce a new tool with which the public is not yet familiar, it is important for EPA to provide complete documentation on its design and application so that we can understand how the tool is used and its results.

CAMx Air Quality Modeling

The evaluation of the CAMx base case performance presented in the Air Quality Modeling Technical Support Document (AQM-TSD) is limited to an operational evaluation of ozone and PM2.5 species using standard statistical comparisons. While these comparisons indicate model performance falls generally within the range of previous studies, EPA has not provided information that establishes the modeling system's ability to capture the physical and chemical processes relevant to interstate transport of air pollution. In addition, these evaluations do not establish the modeling system's ability to correctly quantify the impact of emission reductions on ambient concentrations. For example, it is important to know how the model performed during high pollution events when interstate transport is considered to play a major role. Finally, the very high bias for the crustal/other component raises questions about the quality of the emission inventory for primary PM2.5 and/or the CAMx representation of its transport and removal. These are all important modeling issues that OTC recommends EPA examine prior to the issuance of a final Transport Rule and in developing Transport 2.

The CAMx air quality modeling is based on a 2005 modeling platform. In developing the mobile source emissions for this platform EPA used the National Mobile Inventory Model (NMIM) with MOBILE6 and then applied post processing to approximate the mobile source emissions that would have been computed with EPA's new mobile source model, the Motor Vehicle Emissions Simulator (MOVES) model. Given the non-linear interactions between pollutants from various sources in the atmosphere, it is unclear if using this short cut may have affected the modeling results, in particular the upwind-to-downwind linkages established by the CAMx/PSAT simulations. While OTC supports EPA's choice to use the NMIM and Mobile6 models to meet the Court's timeframe for developing the proposed Transport Rule, OTC urges that for the final Transport Rule and certainly for Transport 2, EPA undertake modeling with updated mobile emissions based on MOVES.

Design Values Calculations

For projecting future average/maximum design values for the daily $PM_{2.5}$ standard, CAMx simulated concentrations of the "other/crustal" component were excluded when determining top 10 percent of “high modeled $PM_{2.5}$ days” for each quarter for relative response factor (RRF) calculations. This approach points to a potential disconnect between observed “high days” and modeled “high days.” OTC believes that this may have implications for the determination of significant contribution and/or nonattainment/maintenance monitors. It is important to ensure that high observed sulfate/nitrate days do, in fact, correspond to high modeled sulfate/nitrate days if this approach is to be utilized.

Further, OTC is interested in ascertaining what alternate selection criteria EPA considered for the RRF calculation (e.g. top 5 percent of CAMx modeled days in each quarter) were explored, so as to allow for confirmation that the RRF calculation being utilized is the most appropriate. Likewise, OTC is concerned as to whether alternatives were considered for calculating quarterly ambient $PM_{2.5}$ concentrations and species fractions, other than the “top 10 percent days,” given the importance of evaluating several approaches here as well. The information provided in the TSD was not sufficient to understand whether alternatives were considered, or that the chosen methods were the best choice.

In EPA’s calculations of 8-hour ozone interstate contributions for the 2012 base case, it appears no RRF and no interstate contributions were calculated at monitors where there are fewer than 5 days with modeled daily max 8-hour ozone concentrations greater than 70 ppb in the 2012 base case simulations. OTC requests that EPA provide additional information indicating if there were any monitors meeting the criteria where interstate contributions could not be calculated. If so, OTC would like to know where these monitors are located, and what their 2012 base case design value/maximum design values may be.

Budget Variability Models

OTC would like to see the approach EPA employs towards variability reevaluated so that the variability is contained within the constraint of each state’s budget. The approach used to calculate the variability in the proposed transport rule would still be appropriate to use, however, there is a discrepancy in the calculations presented by EPA that should be addressed in the final rule. EPA states that variability limits were set to the optimal percentage/tonnage strategy – 10 percent for all three pollutant categories examined, SOx, NOx, and ozone season NOx. However, Tables 15-17 in the Power Sector Variability Technical Support Document (PSV-TSD) show that the optimal variability levels are 8 percent, 5 percent and 8 percent respectively. OTC would like EPA to set the maximum variability at these levels that were calculated to be optimal, rather than at the 10 percent level.

Integrated Planning Model

OTC and its member states are continuing to examine the IPM model and assumptions EPA made in developing proposed Transport Rule. We will write any comments in accordance with EPA’s “Notice of Data Availability Supporting Federal Implementation Plans To Reduce Interstate Transport of Fine Particulate Matter and Ozone” issued on September 1, 2010 and due on October 15, 2010.